ERGON ENERGY

Economic Benchmarking Regulatory Information Notice

Final Submission (Audited)

1 July 2005 to 30 June 2013

ERGON ENERGY CORPORATION LIMITED ABN 50 087 646 062

THIS PAGE IS INTENTIONALLY LEFT BLANK

CONTENTS

DOCUMENT HISTORY

The following table details the versions and date of lodgement (delivery) to the Australian Energy Regulator (AER) of Ergon Energy’s 2005/06-2012/13 Economic Benchmarking RIN submission including attachments.

Document	Description of Change	Lodged	Pages
Ergon Energy’s 2005/06 to 2012/13 Economic Benchmarking Regulatory Information Notice, Initial Submission (unaudited)	Initial Submission in relation to the Initial Regulatory Years (financial years 2005/06 to 2012/13). This Initial Submission is provided on a draft, unaudited basis, without Statutory Declaration as required by the AER’s Notice to allow the AER to commence internal testing and validation of data received from Network Service Providers in response to the Notices. Ergon Energy's 2005/06-2012/13 BM RIN Initial Submission is not available for public disclosure. The Initial Submission is a draft response to the Notice as at 3 March 2014 and it should be recognised that the audit and certification process may drive changes to information presented herein.	Monday, 3 March 2014	Excluding attachments: 93 pages
Ergon Energy’s 2005/06 to 2012/13 Economic Benchmarking Regulatory Information Notice, Final Submission (audited)	Final Submission in relation to the Initial Regulatory Years (financial years 2005/06 to 2012/13), provided on an Audited basis. As relevant, data from the Initial Submission (and associated Basis of Preparation) has been updated following completion of internal, audit and AER reviews. Accompanied by the Audit and Review Report(s) and signed Statutory Declaration.	Wednesday, 30 April 2014	Excluding attachments: 97 pages

GLOSSARY

ACRONYM	GLOSSARY TERM
Ergon Energy 05/06-12/13 Economic Benchmarking RIN	Ergon Energy's 2005/06 to 2012/13 Economic Benchmarking Regulatory Information Notice
ACS	Alternative Control Services
AER	Australian Energy Regulator
Annual Performance RIN	Annual Performance Regulatory Information Notice
CAC	Connection Asset Customers
CAM	AER approved Cost Allocation Method
CAMP	Cost Allocation Methods and Procedures
Capex	Capital Expenditure
CBD	Central business district
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme (AER)
EG	Embedded Generator
Ergon Energy	Ergon Energy Corporation Limited
Excel	Microsoft Excel
Final Submission	In relation to the Initial Regulatory Years only, the information required under the Notice as submitted to the AER on an audited basis in accordance with Appendix D of the Notice and verified by a Statutory Declaration in Appendix C to the Notice, on or before 5:00 pm Australian Eastern Daylight Time (AEDT) on Wednesday, 30 April 2014. The final submission must be accompanied by the Audit and Review Report(s) and a signed Statutory Declaration.
GIS	Geographic information system
ICC	Individually Calculated Customer
Initial Submission	In relation to the Initial Regulatory Years only, the information required under the Notice as submitted to the AER on an unaudited basis, on or before 5:00 pm AEDT on Monday, 3 March 2014.
Initial Regulatory Years	Relevant to the AER's Benchmarking Notice, the financial (regulatory) years 2005/06 to 2012/13.
KM	Kilometre
kV	Kilovolt
LR	Long Rural
MDA	Meter Data Agent
MED	Major Event Day

ACRONYM	GLOSSARY TERM
MVA	Megavolts-ampere
MW	Megawatt
NER	National Electricity Rules
NMI	National Metering Identifier
Nominal	With respect to dollars – means dollar of the day
Notice	Regulatory Information Notice
Opex	Operating Expenditure
POE	Probability of Exceedance
QCA	Queensland Competition Authority
QCA RRS	Queensland Competition Authority Regulatory Reporting Statements
RAB	Regulatory Asset Base
Real	With respect to dollars – means constant dollars at a specific date.
RIN	Regulatory Information Notice
ROAMES	Remote Observation Advanced Modelling Economic Simulation
RRS	Regulatory Reporting Statements
SAC	Standard Asset Customer
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCS	Standard Control Services
SMDB	Statistical Metering Database
STPIS	Service Target Performance Incentive Scheme (AER)
SWER	Single Wire Earth Return
STL	Street lighting
TMED	Major Event Day Threshold
UnMet	Unmetered Customer Category
UR	Urban

1. INTRODUCTION

On 28 November 2013, the Australian Energy Regulator (AER) issued a Regulatory Information Notice (Notice) under Division 4 of Part 3 of the National Electricity (QLD) Law (NEL) to Ergon Energy Corporation Ltd (ABN 50 087 646 062) (Ergon Energy). The Notice was accompanied by the “Better Regulation Explanatory Statement, Regulatory Information Notices to Collect Information for Economic Benchmarking (November 2013)” (RIN Explanatory Statement).

The Notice requires Ergon Energy to provide and to prepare and maintain the information in the manner and form specified in the Notice.

Ergon Energy notes that the AER’s Notice indicates that the AER require the information for the performance or exercise of its functions or powers conferred on it under the NEL or the National Electricity Rules (NER), namely to:

- publish network service provider performance reports (annual benchmarking reports) the purpose of which are to describe, in reasonably plain language, the relative efficiency of each Distribution Network Service Provider (DNSP) in providing direct control services over a 12 month period; and
- assess benchmark operating expenditure (Opex) and benchmark capital expenditure (Capex) that would be incurred by an efficient DNSP relevant to building block determinations.

Pursuant to sections 28F(1)(a) and 28M(e) of the NEL, the Notice requires Ergon Energy to provide the information specified in Schedule 1 to the Notice and prepare and maintain the information in the manner and form specified in Schedule 2 to the Notice.

As required in relation to the Initial Regulatory Years only (financial years 2005/06 to 2012/13), Ergon Energy provided the said information on an unaudited basis electronically to AERInquiry@aer.gov.au, on Monday, 3 March 2014 (the ‘Initial Submission’). It is noted that the AER have used this information to conduct internal testing and validation and contacted Ergon Energy with regards to any perceived anomalies which have been subsequently addressed.

A further submission is required in relation to the Initial Regulatory Years, with information to be provided (electronically) on an audited basis in accordance with Appendix D to the Notice and verified using the Statutory Declaration in Appendix C to the Notice, on or before 5:00 pm AEDT on Wednesday, 30 April 2014 (the ‘Final Submission’). The final submission is to be accompanied by the Audit and Review Report(s) and signed Statutory Declaration.

Accordingly, Ergon Energy is pleased to submit this Final Submission (audited) in relation to the 2005/06 to 2012/13 Regulatory Years **(Ergon Energy 05/06-12/13 Economic Benchmarking RIN, Final Submission),** as made by:

Ergon Energy Corporation Limited
PO Box 1090
Townsville Qld 4810

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

2. CONFIDENTIAL INFORMATION

RIN - Schedule 1 paragraph 1.1, Schedule 2 paragraph 2.1 and 2.3-2.4, Instructions and Definitions

2.1 Requirement

In accordance with Schedule 1 of the Notice, if Ergon Energy makes a claim for confidentiality over any information provided in accordance with the Notice issued, Ergon Energy must:

- comply with the requirements of the AER's Better Regulation Confidentiality Guideline (19 November 2013)[1]; and
- provide, in addition to a confidential version of any information, a version of the information that may be published by the AER.

The AER's Confidentiality Guidelines sets out the framework for how the AER will handle confidentiality claims and requirements for Ergon Energy.

A confidentiality claim, by itself, is insufficient to prevent disclosure. Both the NEL and the *Competition and Consumer Act 2010 (Cth)* provide for the AER to disclose confidential information in certain circumstances. In particular, section 28ZB of the NEL allows the AER to disclose information where:

- disclosure would not cause detriment to the information provider or the person from whom the information provider received the information; or
- public benefit in disclosing the information outweighs that detriment.

Making a confidentiality claim in the manner mentioned above will reduce the chance that the AER will exercise these powers. Ergon Energy notes the AER would provide notice and an opportunity to comment prior to exercising these powers.

2.2 Response

Ergon Energy notes that regard has been given to the AER's Confidentiality Guidelines in assessing confidentiality claims in preparation of its 05/06-12/13 Economic Benchmarking RIN. Ergon Energy has not identified any claims for confidentiality in regards to its 05/06-12/13 Economic Benchmarking RIN response.

Of note, Ergon Energy contacted its independent auditors (Parsons Brinkerhoff, and the Queensland Audit Office) to advise the AER's intention to disclose audit or review reports issued to Ergon Energy in respect of its 2005/06-12/13 Economic Benchmarking RIN, subject to any confidentiality claims made. Confirmation was obtained from both auditors agreeing to the release of their audit or review reports / audit opinion.

[1] Available at: http://www.aer.gov.au/node/18888

3. DATA TEMPLATES

RIN - Schedule 1 paragraph 1.1, Schedule 2 paragraph 2.1, 2.2(d) and 2.3-2.4, RIN Instructions and Definitions section 1.1.1

3.1 Requirement

Schedule 1, paragraph 1.1 of the Notice requires Ergon Energy to provide the information required in the Microsoft Excel workbooks attached at Appendix A to the Notice (the Templates), completed in accordance with the Notice and Instructions and Definitions attached therein (Appendix B).

Schedule 2, paragraph 2.1 requires the Templates to be prepared in a manner and form specified in the worksheets therein and reiterates that the Instructions and Definitions in Appendix B to the Notice are to be adhered to.

Specifically, the AER's Appendix B, Instructions and Definitions section 1.1.1 notes that, subject to a small number of exceptions, Ergon Energy must complete all input cells, meaning a value must be entered that corresponds to the unit required. For the avoidance of doubt, "N/A" or similar must not be input. Exceptions or variables to which this is not applicable (e.g. where input cells can be blacked out) are also detailed in section 1.1.1 of the RIN Instructions and Definitions.

Where *Actual Information* (defined term) cannot be provided, Ergon Energy is required to provide *Estimated Information* and additional information in relation to *Estimated Information* is to be provided in accordance with Basis of Preparation requirements (refer section 4).

For the Final Submission in relation to the Initial Regulatory Years 2005/06-2012/13, the AER requires Ergon Energy to verify information provided in the templates by way of an Audit in accordance with Appendix D and a Statutory Declaration in accordance with Appendix C to the Notice.

3.2 Ergon Energy 2005/06-2012/13 Economic Benchmarking RIN Templates

Ergon Energy's Final Submission of the completed 2005/06-2012/13 Economic Benchmarking RIN templates (05/06-12/13 EBRIN Templates), being the Microsoft Excel workbooks at Appendix A to the Notice, are provided as attachments to this response as follows:

- Consolidated [**EE_0506-1213EBRIN_001F**];
- Estimated [**EE_0506-1213EBRIN_002F**]; and
- Actual [**EE_0506-1213EBRIN_003F**].

In completing the templates, Ergon Energy notes that financial inputs (monetary values) are presented in nominal terms unless otherwise stated and entered in thousands ($'000), rounded to the nearest dollar (unless stated otherwise).

Specifically, non-financial information (except where the RIN requires 'numbers' of units) is provided to at least four significant figures with decimal points added as relevant, but only where the addition of decimal points provides further information.

For responses where the unit is measured in 'numbers' per column C of the templates (such as customer numbers, entry points/exit points etc.) decimal places are not required where they would simply be trailing zeroes.

However, for consistency in display across tables, Ergon Energy has reported data to 3 decimal places.

The table below gives a listing and brief description, of key information systems that Ergon Energy currently uses to provide its Distribution Services and which have been utilised in providing the information required in the templates (referred to as relevant in Basis of Preparation responses provided in section 4).

It is emphasised that this is not an exhaustive list of all of the information systems that Ergon Energy uses. For further explanations of specific processes and systems used to report RIN requirements refer to section 4 in this document.

Table 3-1: Key Information Systems used by Ergon Energy

System	Description
Artemis 7	Manages investment portfolio including project planning, scheduling and tracking, program and project governance and financial and resource management
DCOS Model	Distribution Cost of Supply (DCOS) Model is used in the network tariff setting process, where the output of the model is 'forecast revenue' for each customer group to be recovered via distribution tariffs. The DCOS Model output displays forecast revenues by geographic zones (East, West, Mount Isa) and customer categories (ICC, CAC, EG, SAC, UnMet&STL) with the Annual Charge disaggregated by Fixed Charge, Actual Demand Charge, Capacity Charge, and Volume Charge.
ECORP	ECORPMAIN contains the network asset topology utilised by FeederStat, Connect, Switching Sheet Writer and reliability reporting apps. The ECORP model hierarchy is primarily manually maintained by Network Data Officers and Customer Connection Officers i.e. association of premises with substations. An automated process (GELO) exists which updates selected feeders (approx. 3 feeders) in ECORPMAIN from NETAPP-GISEP. The ECORPMAIN model contains network objects like substations and switches required to model network connectivity it does not contain other assets e.g. poles, conductors, streetlights etc.
Ellipse	Ellipse is a large Enterprise Resource Planning (ERP) application used to manage assets, works, finance, supply chain, logistics, human resources and payroll. This application represents the logical group of modules of the Ellipse application which support the Financial Management sub segment.
FACOM	Ergon Energy's Customer Information System (CIS) which contains customer and premises data. Ergon Energy Queensland's (EEQ) retail customers (Tier 1) and Ergon Energy Corporation Limited's distribution only accounts for Tier 2 (market) customers are managed in FACOM. EEQ's retail customers are billed from FACOM. Information can be extracted from this database using Ergon Energy's ECORP or NetBill applications.
FeederStat	Ergon Energy's outage management system. It pinpoints where a particular premise is located and what feeder or substation it is connected to. FeederStat is used when faults and outages are being analysed and facilitates the National Contact Centre

System	Description
	logging fault related calls as they are received and providing information to customers on restoration times. FeederStat is the primary outage management system employed by Ergon Energy to capture, record, action and report: planned and unplanned outages. FeederStat was internally developed by Ergon Energy and is a common application used across all sites with access to Oracle which is used to both input and extract outage data and information
NEMLink (MDP)	The Meter Data Provider's Market Gateway.
NetBill	Network Bill production for market and non-market customers.
ROAMES	Remote Observation Automated Modelling Economic Simulation (ROAMES) LiDAR program. ROAMES technology originally developed by Ergon Energy and partner organisations, creates precise, 3D geo-spatial representations of network assets such as substations, poles and wire infrastructure to be displayed in a Google Earth-like database. The sheer size of Ergon Energy's distribution area was a key motivator for finding smarter ways of managing the assets and the surrounding environment. It is anticipated that the information ROAMES provides will result in reduced maintenance and planning costs, while also increasing the safety and reliability of electricity supply for our customers and communities. The large volume of data captured during ROAMES flights is processed to enable reliable and precise measurement of Ergon Energy's electricity network and surrounding objects such as buildings, terrain and vegetation. Information is then used to create a precise, virtual representation of Ergon Energy's network infrastructure throughout Queensland, providing vital information for more effective and cost efficient vegetation maintenance and asset planning. From the 1 March 2014, this capability is supplied via a Service Level Agreement from an unrelated corporation called ROAMES Asset Services Pty Limited.
Supervisory Control and Data Acquisition (SCADA)	While SCADA is a general term, it is used within Ergon Energy to refer specifically to the ABB system used for Network Operations.
Smallworld	A geographic information system used to manage the spatial location of assets.
Smallworld Oracle Replicated (SOREP) Spatial database.	Replicated version of Smallworld Electrical Data. Reference by Aires, Mapguide, Google Earth, Schematics etc.
Statistical Metering Database (SMDB)	Statistical Metering Database. Consists of Access databases maintained by Ergon Energy Planning department to capture the history of Ergon Energy's interval data for demand and weather (sourced from the Bureau of Meteorology data).

4. BASIS OF PREPARATION

RIN - Schedule 1 paragraph 1.2, Schedule 2 paragraph 2.2, Appendix B Instruction and Definitions section 1.1.2

4.1 Requirement

Schedule 1 paragraph 1.2 of the Notice requires Ergon Energy to provide a Basis of Preparation demonstrating how Ergon Energy has complied with the Notice, in respect of:

- each variable in each of the worksheets in the Economic Benchmarking Data Templates; and
- other information prepared in accordance with the requirements of the Notice and the RIN Instructions and Definitions at Appendix B to the Notice.

Schedule 2 paragraph 2.2 of the Notice requires the Basis of Preparation to provide, at a minimum, for each variable and any other information, commentary that:

- demonstrates how the information provided is consistent with the requirements of the Notice;
- explains the source from which Ergon Energy obtained the information provided; and
- explains the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy cannot provide input for a Variable using Actual Information and therefore must provide input using Estimated Information, Ergon Energy must also comment as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in this Notice.

Over and above this, Appendix B, Instructions and Definitions section 1.1.2 note (5) requires an additional minimum requirement for the Basis of Preparation for variables that contain Financial Information (Actual and Estimated) where accounting policies adopted by Ergon Energy have materially changed during any of the Regulatory Years covered by the Notice. In such instances, the relevant Basis of Preparation must include an explanation as to the:

- nature of the change; and
- impact of the change on the information provided in response to the notice.

Section 1.1.1 of the Appendix B, Instructions and Definitions also indicates which variables may not be applicable to Ergon Energy as displayed by yellow, orange, or blue shading in the Economic Benchmarking data Templates.

4.2 Basis of Preparation Applied By Ergon Energy

4.2.1 Addressing Minimum Requirements

The following minimum requirements 'A'-'D' are addressed for each of the variables or group of variables contained in the Economic Benchmarking data templates, in sections 4.2.3 through 4.2.9.

Table 4-1: Basis of Preparation Minimum Requirements

	Requirement
A	Demonstrate how the information provided is consistent with the requirements of the Notice
B	Explain the source from which Ergon Energy obtained the information provided
C	Explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made
D	In circumstances where Ergon Energy cannot provide input for a Variable using Actual Information and therefore must provide input using Estimated Information, explain ▪ why an estimate was required, including why it was not possible for Ergon Energy to use Actual Information (as the case may be depending on the Variable); and ▪ the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is Ergon Energy's best estimate, given the information sought in this Notice.
E	For variables that contain Financial Information (Actual and Estimated) the relevant Basis of Preparation must explain if accounting policies adopted by Ergon Energy have materially changed during any of the Regulatory Years covered by the Notice ▪ The nature of the change; and ▪ The impact of the change on the information provided in response to the Notice.

4.2.2 General Comments

Unless otherwise noted, the following general comments are made as relevant to all variables in addressing the minimum requirement '**A'** above:

- Ergon Energy has to the best of its knowledge, complied in all material respects with the requirements of the Notice so issued to Ergon Energy.
- In doing so, Ergon Energy has referred to Appendix B, Instructions and Definitions of the Notice.
- Specifically (and as noted in relevant sections herein), Ergon Energy has referred to section 1.1.1 of the RIN Instructions and Definitions, which indicates variables that may not be applicable to Ergon Energy as displayed by either yellow, orange, or blue shading in the templates.
- Ergon Energy also notes in relation to information provided for the Initial Regulatory Years (2005/06 to 2012/13), Definitions and Interpretations for "Actual Information" and "Estimated Information" have been applied throughout.
- Information has been reported for service categories: Standard Control Services (SCS) (and where relevant – Network Services) and Alternative Control Services (ACS) in accordance with RIN requirements and with reference to the Instructions and Definitions.

- As relevant (and as noted in relevant sections herein), Ergon Energy has included any additional information required to be prepared in accordance with the requirements of the Notice.
- In completing the templates, Ergon Energy notes financial inputs (monetary values) are presented in nominal terms unless otherwise stated and entered in thousands ($'000), rounded to the nearest dollar (unless stated otherwise).
- In accordance with clarification provided by the AER[2], Non-financial information is provided to at least four significant figures with decimal points as relevant, but only where the addition of decimal points provides further information.
- Where relevant, regard has also been given to the Better Regulation Explanatory Statement, Regulatory Information Notices to collect information for economic benchmarking, November 2013 though it is noted that in any instances of inconsistency, the Notice is taken to have precedence.

4.2.3 Revenue

The AER requires revenue data to be provided, disaggregated in accordance with the main outputs for which Ergon Energy bills its customers. Ergon Energy understands that the AER is collecting revenue data to allow for the application of an 'as billed' (or billed outputs) specification in addition to a functional outputs specification. The 'as billed' basis measures outputs in terms of the services for which businesses charge customers.

The Appendix B, Instructions and Definitions require Ergon Energy to report revenues split in accordance with the categories in the template tables, as discussed individually below.

Separately, Ergon Energy is required to report revenues received/deducted as a result of incentive schemes.

Revenues must be split in accordance with definitions of SCS and ACS, which also recognise periods where different service classifications applied. Furthermore, zeroes ('0') are permissible only when no effect on Revenues is applicable to Ergon Energy.

4.2.3.1 Revenue Grouping By Chargeable Quantity

Template 2, table 2.1 requires Ergon Energy to allocate revenues to the chargeable quantity that most closely reflects the basis upon which the revenue was charged by Ergon Energy to customers (the chargeable quantities are the variables DREV0101-DREV0112).

Revenues that cannot be allocated to the specific chargeable quantities in variables DREV0101 to DREV0112 must be reported against 'Revenue from other sources' (DREV0113).

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for 'Revenue Grouping by Chargeable Quantity'. Of note, DREV01 'Total Revenue by Chargeable Quantity' represents the sum variables DREV0101-DREV0113, and is therefore implicitly addressed in the responses below.

[2] 22 January 2014

Table 4-2: Revenue Grouping by Chargeable Quantity

Variable		Addressing Basis of Preparation Requirements
	A	All mandatory data entry fields shaded yellow, have been populated.
DREV0101-DREV0109 DREV0112 - (SCS)		Ergon Energy confirms, as required by the AER in Box 1, Revenue Financial Reporting Framework of Appendix B, Instructions and Definitions that Revenues reconcile to the Direct Control Services revenues in Regulatory Accounting Statements as per the Annual Reporting Requirements (AER defined term) as submitted to the relevant regulator, for the year in question). Direct Control Services, which were charged by Ergon Energy to customers (in accordance with the BM RIN instructions at Section 2: Revenue) have been reported as ▪ Standard Control Services (SCS): Network Services, Connection Services, Metering Services, Capital Contributions; and ▪ Alternative Control Services (ACS): Street lighting, Quoted services, Fee based services, Contributions. In accordance with the definition for Standard Control Services, for Ergon Energy this includes prescribed services as determined by the Queensland Competition Authority (QCA) for 2005/06 – 2009/10. In the QCA Final Determination, Chapter 3 page 54-55, Ergon Energy's approved Prescribed Distribution Services (PDS) included public lighting construction and maintenance. Accordingly, public lighting revenue has been reported as an SCS for the 2005/06 – 2009/10 regulatory years. For 2010/11 – 2012/13 regulatory years, Street Lighting Services were classified as an ACS as noted in Appendix A: Distribution Service Classification of the AER's Final Distribution Determination for 2010-2015. Therefore, public lighting for the recovery of construction and maintenance costs for 2010/11 – 2012/13 regulatory years has been reported as an ACS (refer to the source and methodology in Table 4-3: Revenue Grouping by Chargeable Quantity under heading DREV0112: Public Lighting). Note: the recovery of the Distribution use of System's charge in respect of Public Lighting has been reported as a SCS for all years. Ergon Energy's approved services are as per the Framework and Approach as displayed in Chapter 2 of the AER Final Distribution Determination, and Chapter 3.5 of the QCA Final Determination. This correlates to Distribution use of System charges and Capital Contributions for SCS and Other Revenue and Contributions for ACS as displayed in the regulatory accounting statements. Revenue reported in prior regulatory accounting statements which is not a Direct Control Service charged by Ergon Energy to Customers include: profit or gross proceeds on sale of assets, interest received, shared assets revenue and Transmission use of System charges, Sales. Rather, they were specific reporting requirements of prior regulatory instruments. 'Revenue from Unmetered Supplies' is the same for template 2, table 2.1 (DREV0107) as for template 2, table 2.2 (DREV0205). Public lighting has been reported in variable (DREV0112) and has been excluded from 'revenue from unmetered supplies' (DREV0107). This is based on the interpretation of the definitions for unmetered supplies and customer numbers. The latter states public lighting connections are not to be

Variable		Addressing Basis of Preparation Requirements
		counted when calculating the number of unmetered customers. Ergon Energy does not charge customers for the following items and accordingly, yellow cells have been populated with ‘0’, as per instructions in the Notice: ▪ DREV0103: Revenue from On–Peak Energy Delivery charges, ▪ DREV0104: Revenue from Shoulder period Energy Delivery Charges; and ▪ DREV0105: Revenue from Off–Peak Energy Delivery charges. The total of revenues by chargeable quantity for these variables reconciles to the total revenues by customer class (DREV02).
	B	Data has been sourced as follows: a) Monthly Network Billing (Netbill) files provided by Ergon Energy’s Service Transaction Centre (STC) for 2011/12 and 2012/13; and b) Actual DUOS revenue received sourced from the annual summary of Netbill files, allocated to variables using forecasts from the annual Distribution Cost of Supply (DCOS) Model maintained by Ergon Energy’s Pricing Team for 2005/06 – 2010/11. The STC is responsible for Network Billing and the recovery from Retailers of the Network Use of Systems (NUOS) and service related charges. A priority of the STC is to manage the revenue recovery process to ensure Ergon Energy meets its revenue cap. The DCOS Model is used in the network tariff setting process, where the output of the model is ‘forecast revenue’ for each customer group to be recovered via distribution tariffs. The DCOS Model output displays forecast revenues by geographic zones (East, West, Mount Isa) and customer categories (ICC, CAC, EG, SAC, UnMet&STL) with the Annual Charge disaggregated by Fixed Charge, Actual Demand Charge, Capacity Charge, and Volume Charge.
	C	Ergon Energy‘s methodology applied to provide information for 2011/12 and 2012/13 is based on actual data in Netbill files. This revenue was able to be mapped directly to the variables required using Ergon Energy‘s (network) charge categories. Information for 2005/06 to 2010/11 is derived by assigning actual DUOS revenue received to the required variables (DREV0101, DREV0102, DREV0106 - DREV0109, and DREV0112) based on a percentage apportionment of forecast revenue (in the DCOS Model). The table below sets out the mapping of DCOS model charges to RIN variables.

DCOS model	Benchmarking RIN Variable
Fixed Charges	Revenue from Fixed Customer Charges
Actual Demand Charges	Revenue from Measured Maximum Demand Charges
Capacity Charge Minimum Chargeable Demand	Revenue from Contracted Maximum Demand Charges
Volume Charge	Revenue from Energy delivery charges where time of use is not a determinant

Revenue from controlled load customer charges (DREV0106) and Revenue from unmetered supplies (DREV0107) are inclusive of Fixed Charges i.e.: these charges

Variable		Addressing Basis of Preparation Requirements
		haven't been separately reported in Revenue from Fixed Customer Charges (DREV0101). For Revenue from Contracted Maximum Demand charges (DREV0108) and Revenue from Measured Maximum Demand charges (DREV0109), Ergon Energy has allocated the 'full recovery of revenue from customers on the SAC – Large tariff' to Contracted Demand. Ergon Energy has adopted this approach as it is consistent with the approach used for Table 5.3.6 'Demand supplied' where instructions state, 'where Ergon Energy cannot distinguish between contracted and measured Maximum Demand, demand supplied must be allocated to contracted Maximum Demand. These customers have a minimum demand charge which is unable to be easily spilt between contracted and measured demand without extensive work to investigate each single monthly billing for each connection on this tariff. Revenue from Public Lighting (DREV0112) has been reported as either a SCS or ACS based on its service classification for the relevant regulatory control period.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 2, table 2.1 for all years. Sources used are historical accounting records from Netbill files and Ergon Energy's DCOS Model which is a tool used in the normal course of business for preparing forecasts for pricing purposes. Disaggregation of total actual revenues extracted from Netbill was performed based on the methodologies employed within DCOS modelling of forecast revenue for years 2005/06 – 2010/11. A manually intensive check was performed on a sample two year period (2011/12 and 2012/13) of Netbill data extracts available at the required disaggregation, compared to that arrived at via the DCOS disaggregation approach. This revealed the calculated disaggregation for 2011/12 and 2012/13 to be within <3% of the Netbill extracts, indicating the approach was materially correct and could be reasonably applied to 2005/06 – 2010/11 Netbill extracts. As results are materially dependent on records used in the normal course of business, all results have been reported as actual information.
	E	No accounting policies adopted by Ergon Energy have materially changed during any of the Regulatory Years covered by the Notice, in relation to variables contained in template 2, table 2.1.

Table 4-3: Revenue Grouping by Chargeable Quantity

Variable		Addressing Basis of Preparation Requirements
DREV0110- **DREV0112 -** **(ACS)** **DREV0113** **DREV01**	A	All mandatory data entry fields shaded yellow, have been populated. Ergon Energy confirms, as required by the AER in Box 1, Revenue Financial Reporting Framework of Appendix B, Instructions and Definitions that Revenues reconcile to the Direct Control Services revenues in Regulatory Accounting Statements as per the Annual Reporting Requirements as submitted to the relevant regulator, for the year in question). Direct Control Services, which were charged by Ergon Energy to customers (in accordance with the BM RIN instructions at Section 2: Revenue) have been reported as ▪ Standard Control Services (SCS): Network Services, Connection Services, Metering

Variable	Addressing Basis of Preparation Requirements
	Services, Capital Contributions; and ▪ Alternative Control Services (ACS): Street lighting, Quoted services, Fee based services, Contributions. In accordance with the definition for Standard Control Services, for Ergon Energy this includes prescribed services as determined by the Queensland Competition Authority (QCA) for 2005/06 – 2009/10. In the QCA Final Determination, Chapter 3 page 54-55, Ergon Energy's approved Prescribed Distribution Services (PDS) included public lighting construction and maintenance. Accordingly, public lighting revenue has been reported as an SCS for 2005/06 – 2009/10 regulatory years. For 2010/11 – 2012/13 regulatory years, Street Lighting Services were classified as an ACS as noted in Appendix A: Distribution Service Classification of the AER's Final Distribution Determination for 2010-2015. Therefore, public lighting for the recovery of construction and maintenance costs for 2010/11 – 2012/13 regulatory years has been reported as an ACS (refer to the source and methodology below at DREV0112: Public Lighting). Note: the recovery of the Distribution use of System's charge in respect of Public Lighting has been reported as a SCS for all years. Ergon Energy's approved services are as per the Framework and Approach as displayed in Chapter 2 of the AER Final Distribution Determination, and Chapter 3.5 of the QCA Final Determination. This correlates to Distribution use of System charges and Capital Contributions for SCS and Other Revenue and Contributions for ACS as displayed in the regulatory accounting statements. Revenue reported in prior regulatory accounting statements which is not a Direct Control Service charged by Ergon Energy to Customers include: profit or gross proceeds on sale of assets, interest received, shared assets revenue and Transmission use of System charges, Sales. Rather, they were specific reporting requirements of prior regulatory instruments. 'Revenue from Unmetered Supplies' is the same for template 2, table 2.1 ('DREV0107) as for template 2, table 2.2 (DREV0205). Public lighting has been reported in variable (DREV0112) and has been excluded from 'revenue from unmetered supplies' (DREV0107). This is based on the interpretation of the definitions for unmetered supplies and customer numbers. DREV0107 states public lighting connections are not to be counted when calculating the number of unmetered customers. DREV01: Total revenue by chargeable quantity for years 2005/06 to 2009/10 is the Total Revenue reported in the QCA RRS less Revenue from disposal of PP&E, Income from investments, Other income, and Adjustment for use of revenue cap assets by non-regulated users, and TUOS. DREV01: Total revenue by chargeable quantity for years 2010/11 to 2011/12 is the Total Revenue reported in Ergon Energy's Annual Performance RIN less Use of Gross proceeds from sale of assets, Interest income, and Revenue Cap Reg Assets by Non-SCS Users. DREV01: Total revenue by chargeable quantity for 2012/13 is the Total Revenue reported in Ergon Energy's 2012/13 Annual Performance RIN less Use of Gross proceeds from sale of assets, Interest income, and Revenue Cap Reg Assets by Non-

Variable		Addressing Basis of Preparation Requirements
		SCS Users and TUOS revenue.
	B	Ergon Energy has sourced the data from previously audited Ergon Energy's Annual Performance RIN's, for the years 2010/11 to 2012/13. For the years 2005/06 to 2009/10 the data is from the previously audited QCA regulatory reporting statements (QCA RRS).
	C	DREV0110: Metering codes: ▪ SCS is zero for years 2005/06 to 2012/13. The revenue is reported as part of DUOS. There is no meaningful way to separate the metering code revenue from DUOS. ▪ ACS is zero for years 2005/06 to 2006/07. There is no revenue for Excluded Distribution Services for this period as the reclassification of services from Non-Duos to Excluded Distribution Services occurred in December 2007. ▪ ACS for years 2007/08 to 2010/11. This revenue is taken directly from Schedule C: Regulatory Statement of Financial Returns. The Individual Service items categorised as Metering have been collated from Schedule C. ▪ ACS for 2010/11. The revenue is from a detailed source data file which reconciles to the 2010/11 Annual Performance RIN ACS Revenue in Template 7a Statement of Financial Performance. The source file was collated using FACOM and Ellipse data to disaggregate volumes and revenue for fee and quoted services for Ergon Energy's Pricing Proposal. ▪ ACS for 2011/12. The revenue is from the Fee based services file used for the Pricing Proposal. The products categorised as Metering have been collated from the data file. ▪ ACS for 2012/13. The revenue is taken directly from Template 17: Alternative Control Services & Other, Table 1. Alternative Control & Other Services in Ergon Energy's 2012/13 Annual Performance RIN. DREV0111: Connection Charges: ▪ SCS for years 2005/06 to 2009/10. The revenue is taken directly from Statement 1: Regulatory statement of financial returns: Disaggregated by type of service in the QCA RRS. It is the Capital Contributions in DUOS services. ▪ SCS for years 2010/11 to 2012/13. This revenue is taken directly from the Income Statement in Ergon Energy's 2012/13 Annual Performance RIN. It is the Capital Contributions in Standard Control Services. ▪ Excluded Services for years 2005/06 to 2009/10. No Revenue was received in Statement 1: Regulatory statement of financial returns for Capital Contributions in the years 2005/06 to 2009/10. ▪ ACS for years 2010/11 to 2012/13. This revenue is taken directly from the Statement of Financial Performance in the Ergon Energy's 2012/13 Annual Performance RIN. DREV0112: Public Lighting: ▪ SCS for years 2005/06 to 2012/13. Refer to table above Table 4-2: Revenue Grouping by Chargeable Quantity. ▪ ACS for years 2005/06 to 2009/10. Public lighting was classified as a SCS for these

Variable	Addressing Basis of Preparation Requirements
	years, therefore there is nothing to report. ▪ ACS for years 2010/11 to 2012/13. The revenue has been taken directly from the Statement of Financial Performance (Distribution line) in Ergon Energy's 2012/13 Annual Performance RIN. DREV0113: Revenue from Other Sources: ▪ SCS, nothing to report. ▪ ACS for years 2005/06 to 2009/10. The revenue is zero for years 2005/06 to 2006/07. There is no revenue for Excluded Distribution Services in the QCA RRS for those years. ▪ ACS for years 2007/08 to 2009/10. The revenue is taken directly from Schedule C: Regulatory Statement of Financial Return. The Individual Service items not categorised as Metering have been collated from Schedule C. Therefore it is the total income from the Excluded Distribution Services less any metering revenue. ▪ ACS for 2010/11. The revenue is sourced from the Reconciliation of the 2010/11 RIN ACS Revenue with the detailed service level Pricing ACS revenue data file. The revenue is the total less the metering revenue. ▪ ACS for 2011/12. The revenue is from the Fee based services file used for the annual Pricing Proposal. The revenue is the total less the metering revenue. ▪ ACS for 2012/13. The revenue is taken directly from Table 1. Alternative Control & Other Services in Ergon Energy's 2012/13 Annual Performance RIN. The revenue is the total less the metering revenue.
D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to these variables contained in template 2, table 2.1.
E	No accounting policies adopted by Ergon Energy have materially changed during any of the Regulatory Years covered by the Notice, in relation to variables contained in template 2, table 2.1.

4.2.3.2 Revenue Grouping by Customer Type or Class

Template 2, table 2.2 requires Ergon Energy to allocate revenues to the customer type or class that most closely reflects the customers from which revenues are received. Revenues that Ergon Energy cannot allocate to the customer types DREV0201-DREV0205 must be reported against 'Revenue from other Customers' (DREV0206).

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for 'Revenue Grouping by Customer Type or Class'. Of note, DREV02 'Total Revenue by Customer Class' represents the sum variables DREV0201-DREV0206, and is therefore implicitly addressed in the comments below.

Table 4-4: Revenue Grouping by Customer Type or Class

<table>
<tr><th>Variable</th><th colspan="2">Addressing Basis of Preparation Requirements</th></tr>
<tr><td rowspan="3">DREV0201-
DREV0206
DREV02</td><td>A</td><td>All mandatory data entry fields shaded yellow, have been populated.

Ergon Energy confirms, as required by the AER in Box 1, Revenue Financial Reporting Framework of its Instructions and Definitions, that Revenues reconcile to the Direct Control Services revenues in Regulatory Accounting Statements as per the Annual Reporting Requirements (AER defined term) as submitted to the relevant regulator, for the year in question.

‘Revenue from Unmetered Supplies’ is the same for template 2, table 2.1 (‘DREV0107) as for template 2, table 2.2 (DREV0205).</td></tr>
<tr><td>B</td><td>Ergon Energy has sourced information from:

▪ Monthly Network Billing (Netbill) files provided by the STC.</td></tr>
<tr><td>C</td><td>Historically, Ergon Energy’s Network Tariffs have not been aligned to a specific customer class and we therefore do not have Revenue data based on the disaggregation required, with a few exceptions.

Capital Contributions have been recorded as ‘Revenue from Other Customers’ in Table 2.2 ‘Revenue grouping by customer type of class’ as opposed to the customer type variables set by the AER. Unlike DUOS revenue which can be allocated to customer type variables using the DCOS model, Contributions don’t have a secondary system to verify the customer classes to allow mapping to these categories. Therefore, EECL has adopted the approach in the Instructions and Definitions document which states:

▪ Revenues that Ergon Energy cannot allocate to the customer types DREV0201–DREV0205 must be reported against ‘Revenue from other Customers’ (DREV0206).

Ergon Energy has employed the following mapping in this regard.

<table>
<tr><th></th><th>BENCHMARING RIN VARIABLES</th><th>ERGON NETWORK TARIFF</th><th>ERGON TARIFF DESCRIPTION</th></tr>
<tr><td colspan="2">Table 2.2 Revenue grouping by Customer type or class</td><td></td><td>Typical Consumption Levels</td></tr>
<tr><td>DREV0201</td><td>Revenue from residential Customers</td><td>Volume Small, Night Controlled and Controlled</td><td>Energy Consumption below 26MWh p.a.
No demand component</td></tr>
<tr><td>DREV0202</td><td>Revenue from non-residential customers not on demand tariffs</td><td>Volume Large</td><td>Energy Consumption between 26MWhs and 100MWhs
No demand component</td></tr>
<tr><td>DREV0203</td><td>Revenue from non-residential low voltage demand tariff customers</td><td>Demand High Voltage, Demand Large, Demand Medium and Demand Small</td><td>Energy Consumption between 100MWhs and 4,000MWhs.
Demand charge based on minimum chargeable demand</td></tr>
</table>
</td></tr>
</table>

Variable	Addressing Basis of Preparation Requirements			
	DREV0204	Revenue from non-residential high voltage demand tariff customers	ICC, CAC and EMG	Energy Consumption greater than 4,000MWhs Demand based on Authorised or Capacity component and an Actual Demand component
	DREV0205	Revenue from unmetered supplies	Unmetered Supply - Minor and Major Streetlights;	Unmetered Supply connections other than Streetlights No demand component
	DREV0206	Revenue from Other Customers	Unmetered Supply - Minor and Major Streetlights (SCS only), Contributions	Unmetered Supply - Minor and Major Streetlights No demand component
	DREV02	Total revenue by customer class	Total Revenue	Total Revenue

	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to variables DREV0205, DREV0206 and DREV02 contained in template 2, table 2.2. The disaggregation for all other variables has been estimated using the above mapping table as this is Ergon Energy's best estimate.
	E	No accounting policies adopted by Ergon Energy have materially changed during any of the Regulatory Years covered by the Notice, in relation to variables contained in template 2, table 2.2.

4.2.3.3 Revenue (Penalties) Allowed (Deducted) Through Incentive Schemes

Template 2, table 2.3 requires Ergon Energy to report the penalties or rewards of incentive schemes. The penalties or rewards from the schemes applied by previous jurisdictional regulators that are equivalent to the Service Target Performance Incentive Scheme (STPIS) or Efficiency Benefit Sharing Scheme (EBSS) must be reported against the line items for those schemes.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for 'Revenue (penalties) allowed (deducted) through incentive schemes'. Of note, DREV03 'Total revenue of incentive schemes' represents the sum variables DREV0301-DREV0303 and is therefore implicitly addressed in the table below.

Table 4-5: Revenue (Penalties) Allowed (Deducted) through Incentive Schemes

Variable		Addressing Basis of Preparation Requirements
DREV0301-DREV0303 **DREV03**	A	All mandatory data entry fields shaded yellow, have been populated. Ergon Energy confirms that revenues reported in template 2, table 2.3 reflect the effect on revenues of incentive schemes in the year that the penalty or reward is applied (as opposed to when it was earned which depending on the scheme may be in earlier years). Ergon Energy confirms, as required by the AER in Box 1, Revenue Financial Reporting Framework of Appendix B, Instructions and Definitions that Revenues reconcile to the Direct Control Services revenues in Regulatory Accounting Statements as per the Annual

Variable		Addressing Basis of Preparation Requirements
		Reporting Requirements (AER defined term) as submitted to the relevant regulator, for the year in question.
	B	Incentive schemes applicable to Ergon Energy relate to the EBSS and STPIS schemes – commencing from 1 July 2010. The only impact during the initial regulatory years on revenues relates to the STPIS in the 2012/13 year. The penalty under this scheme has been sourced from the revenue adjustment applied for STPIS in the Maximum Allowable Revenue (MAR) formula in the 2012/13 Pricing Proposal.
	C	The STPIS penalty has been taken from the revenue adjustment applied for STPIS in the Maximum Allowable Revenue (MAR) formula in the 2012/13 Pricing Proposal.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 2, table 2.3.
	E	No accounting policies adopted by Ergon Energy have materially changed during any of the Regulatory Years covered by the Notice, in relation to variables contained in template 2, table 2.3.

4.2.4 Opex

The AER requires Ergon Energy to provide Operating Expenditure (Opex) by category to identify the drivers of change in the partial productivity of Opex. Ergon Energy understands that the AER are requesting Opex data for economic benchmarking purposes, as the key input required for DNSPs to deliver their services. It is further understood that the AER believe collecting this information will also allow for the costs of providing these services to be taken into account when conducting sensitivity analysis.

The AER also requires Opex to be reported for Network Services as these are the services that the AER intends to analyse in their economic benchmarking.

Further, Opex is required in accordance with both historical and current reporting arrangements such that the effect of any Material changes in reporting approach on efficiency measurement can be taken into account. The AER suggests that a Material change would include a change in capitalisation policy that significantly shifts costs from Opex to Capex or a change in the categories of Opex reported.

Where Opex is not incurred for a particular variable, zeroes ('0') are permitted, including where Ergon Energy does not provide a service as part of (for example) SCS or ACS.

Information is also required in relation to each of Ergon Energy's individual Provisions, namely, the Opex and Capex components of Provisions in relation to SCS only.

Finally, Opex for high voltage customers must be reported in terms of end user costs (not SCS). This is to represent the cost Ergon Energy would have incurred had it been responsible for operating and maintain the electricity Distribution Transformers that are owned by its high voltage customers.

4.2.4.1 Opex Categories

Template 3, table 3.1 (comprising tables 3.1.1 and 3.1.2) requires Ergon Energy to report Opex in accordance with the categories reported in response to Annual Reporting Requirements (AER defined term).

Current Opex Categories and Cost Allocations

Of note, the blue shaded cells of template 3, table 3.1.1 become compulsory only where there has been a Material change (over the course of the back cast time series) in Ergon Energy's:

- Cost Allocation Approach;
- Basis of preparation for its Regulatory Accounting Statements; or
- Annual Reporting Requirements.

A material change in this context is defined by the AER to be a change in Opex of greater than half of a per cent of total SCS (Opex) in the year that the change occurred.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for 'Current Opex categories and Cost Allocations'. Of note, DOPEX01 'Total Opex' represents the sum variables DOPEX0101-DOPEX0114, and is therefore implicitly addressed in the table below.

Table 4-6: Current Opex Categories and Cost Allocations

Variable		Addressing Basis of Preparation Requirements
DOPEX0101-DOPEX0113 DOPEX01	A	Ergon Energy considers that a material change has occurred in its CAM between the current (2010-15) and prior (2005-10) regulatory control periods. Based on the comparison between historical and current cost allocation approach for Opex in 2009/10, the change in CAM has resulted in a 7% decrease to operating costs. This meets the Instructions requirement of a material change which states a change in Opex of greater than half of a per cent of total SCS Opex in the year that the change occurred is material. Accordingly, variables DOPEX0101 – DOPEX0113 (and subsequently, total DOPEX01) are considered mandatory and have been populated by Ergon Energy, despite being shaded blue to allow for blacked out data input. Variables DOPEX0101 – DOPEX0103 have been assigned a category name. Variable DOPEX0104—DOPEX0113 represent additional variables (rows) inserted for other Opex categories as required by Ergon Energy and allowed for under the Notice Instructions and Definitions. Ergon Energy confirms, as required by AER in Box 2, *Reporting Framework – Table 3.1.1 Current Opex categories and allocations* in its Instructions and Definitions that Opex has been prepared for all Regulatory Years in accordance with Ergon Energy current approved AER CAM. For clarity, the AER's Classification of Services per the current regulatory control period (2010-15) as referenced in that CAM have been applied for opex tables 3.1.1 and 3.2.1. Directions within the Annual Reporting Requirements for the most recently completed 2012/13 Regulatory Information Notice as submitted to the AER have been applied for all Regulatory Years. Opex has been reported in accordance with the categories required by the AER's Notice. Opex has been reported in accordance with the categories as disclosed in the

Variable		Addressing Basis of Preparation Requirements
		2012/13 Regulatory Information Notice as submitted to the AER. Historical Opex for Standard Control Services and Alternative Control Services reconciles to historical Opex as disclosed in Ergon Energy's response to Annual Reporting Requirements for years 2010/11-2012/13. Ergon Energy does not currently own, control or operate any dual-function assets for inclusion in Opex. Ergon Energy does not have any subsidiaries which provide operating and maintenance services to the DNSP therefore reporting of margins are not applicable. Where relevant (namely, during the current regulatory control period), total Opex equals that reported against the Annual Reporting Requirements (AER defined term) provided to the AER or QCA respectively.
	B	Ergon Energy has sourced the data used to populate template 3, table 3.1.1 from the audited Ellipse general ledger for the relevant year.
	C	Ergon Energy has obtained the data directly from the Annual Performance RIN's for 2010/11 – 2012/13, and for prior years the Ellipse Trial Balance for each financial year was loaded into an Access Database which contains mappings between the Ellipse account codes (product /activity) and the relevant reporting variable (DOPEX0101 – DOPEX0113). A query was run to extract costs against the relevant reporting variables. For example: Activity 52130 (Preventative Meters) is mapped to variable Preventive Maintenance. This is the same mapping process adopted for reporting the Annual Performance RINs.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 3, table 3.1.1.
	E	Ergon Energy notes that a material change has occurred in its cost allocation approach (affecting Capex and Opex) between the current (2010-15) and prior (2005-10) regulatory control periods. A new (still current) CAM was approved by the AER on 5 March 2009 replacing the prior approved Cost Allocation Method and Principles (CAMP) approved by the Jurisdictional regulator, the QCA on 2 May 2006 (1 July 2005 – 30 June 2010). Changes to the CAM (versus CAMP) include: ▪ In the years 2005/06 to 2009/10 overheads were allocated on the basis of labour dollars only. In the subsequent years overheads have been allocated in accordance with the AER approved CAM on a full-cost basis; ▪ Training costs for the years 2005/06 to 2009/10 were split between operating and capital in accordance with accounting standards. In the subsequent years training costs have been treated as an operating cost only; ▪ Street Lighting Services were reclassified as an Alternative Control Service under the CAM (previously a Prescribed Distribution Service). ▪ The impact of the above changes can be seen by comparing template 3, tables 3.2.1 and 3.2.2.

Historical Opex Categories and Cost Allocations

Template 3, table 3.1.2 requires Ergon Energy to report its historical Opex categories in accordance with the Opex activities (e.g. vegetation management, emergency response Opex, etc.) within the Annual Reporting Requirements (AER defined term) that applied in the relevant Regulatory Year. These categories must align with the activities reported in response to the Annual Reporting Requirements for each Regulatory Year.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for 'Historical Opex categories and cost allocations'. Of note, DOPEX01A 'Total Opex' represents the sum of variables DOPEX0101A - DOPEX0116A, DOPEX0101B - DOPEX0113B and DOPEX0101C - DOPEX0113C and is therefore implicitly addressed in the table below.

Table 4-7: Historical Opex Categories and Cost Allocations

Variable	Addressing Basis of Preparation Requirements
DOPEX0101A- DOPEX0116A DOPEX01A DOPEX0101B-- DOPEX0114B DOPEX01B DOPEX0101C- DOPEX0113C DOPEX01C A	All mandatory data entry fields shaded yellow, have been populated. Variable DOPEX0101A - DOPEX0114A and DOPEX0101B - DOPEX0116B represent additional variables (rows) inserted for other Opex categories as required by Ergon Energy and allowed for under the Notice Instructions and Definitions. Ergon Energy confirms, as required by the AER in Box 3, *Reporting Framework – Table 3.1.2 Historical Opex categories and allocations* in its Instructions and Definitions, that Opex has been prepared for all Regulatory Years in accordance with Ergon Energy approved CAM (AER) or CAMP (QCA) as in effect for the individual regulatory year. Similarly, the principles and approach or requirements pertaining to the prevailing Annual Reporting Requirements relevant to each individual year were applied in reporting Opex for that Regulatory Year. Although TUOS expenditure was reported as an Operating cost under the QCA RRS it has been excluded from this table as it does not fit the definition of Opex in the Instructions and Definitions document. TUOS is considered to be a pass through of costs to the retailer for reimbursement to the transmission provider and not of cost of operating and maintaining the distribution network. Opex has been reported in accordance with the categories as disclosed in Annual Reporting Requirements in effect for that year. Of note, Fee Based and Quoted Services classified as an Excluded Distribution Service for the years 2005/06 – 2009/10 have been reported as 'Other Services' and those services classified as Alternative Control Services for the years 20010/11 – 2012/13 have been reported as 'Customer Services' based on the Annual Reporting Requirements for the respective instruments. Historical Opex for Standard Control Services and Alternative Control Services reconciles to historical Opex as disclosed in Annual Reporting requirements, with the exception of TUOS expenditure (2005/06 to 2009/10) as mentioned above. As Ergon Energy does not currently own, control or operate any dual-function assets, there is no associated Opex to report. Ergon Energy does not have any subsidiaries which provide operating and maintenance services to the DNSP; therefore reporting of margins is not applicable.

Variable		Addressing Basis of Preparation Requirements
	B	Ergon Energy has sourced the data used to populate template 3, table 3.1.2 from previously audited QCA RRS or the AER Annual Reporting RINs for the relevant year.
	C	Each variable in the Table has been populated by extracting the previously reported values against each historical Opex category.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 3, table 3.1.2.
	E	Refer response to minimum requirement E for Current Opex Categories and Cost Allocations above, which noted changes in historical cost allocation approaches impacting both Capex and Opex.

4.2.4.2 Opex Consistency

The AER requires data in relation to consistent Opex line items for economic benchmarking. Network Services Opex is requested as this the core service which the AER intends to benchmark. Other services are collected so that their impact on productivity can be assessed and they can be incorporated or excluded from the services being benchmarked if necessary.

Opex Consistency – Current Cost Allocation Approach

Template 3, table 3.2.1 requires Ergon Energy to report Opex Variables in accordance with its current reporting arrangements (such as its Cost Allocation Approach). These variables are only required to be completed if there has been a Material change (over the course of the back cast time series) in Ergon Energy's:

- Cost Allocation Approach, or
- Basis of Preparation for its Regulatory Accounting Statements, or
- Annual Reporting Requirements (AER defined term).

A material change in this context is defined by the AER to be a change in Opex of greater than half of a per cent of total SCS (Opex) in the year that the change occurred.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for 'Opex Consistency – Current Cost Allocation Approach'.

Table 4-8: Opex Consistency – Current Cost Allocation Approach

Variable		Addressing Basis of Preparation Requirements
DOPEX0201-DOPEX0206	A	Ergon Energy considers that a material change has occurred in its CAM between the current (2010-15) and prior (2005-10) regulatory control periods. A material change in this context is a change in Opex of greater than half of a per cent of total Standard Control Services Opex in the year that the change occurred. Based on the comparison between historical and current cost allocation approach for Opex in 2009/10, the change in CAM has resulted in a 7% decrease to operating costs. Accordingly, AER variables DOPEX0201 – DOPEX0206 are considered mandatory and have been populated by Ergon Energy, despite being shaded blue to allow for blacked out data input.

Variable	Addressing Basis of Preparation Requirements
	Ergon Energy confirms, as required by the AER in Box 4, *Reporting Framework – Table 3.2.1 Opex Consistency - Current Cost Allocation Approaches* in its Instructions and Definitions that Opex has been prepared for all Regulatory Years in accordance with Ergon Energy's current AER CAM. For clarity, the AER Classification of Services per the current regulatory control period (2010-15) as referenced in that CAM have been applied for opex tables 3.1.1 and 3.2.1 Directions within the Annual Reporting Requirements for the most recently completed 2012/13 Annual Performance RIN as submitted to the AER have been applied for all Regulatory Years. Ergon Energy did not report any material changes in Accounting Principles for the reporting period. Opex has been reported in accordance with the categories required by the AER's Notice. Opex for transmission connection point planning is considered a Network Service as it is an activity involved in planning the network. In accordance with the RIN Instructions and Definitions, this amount has been included under both variables DOPEX0201: Opex for network services and DOPEX0206: Opex for transmission connection point planning, resulting in a double count of this amount in Table 3.2. As Ergon Energy does not currently own, control or operate any dual-function assets, there is no associated Opex to report. Ergon Energy does not have any subsidiaries which provide operating and maintenance services to the DNSP therefore reporting of margins is not applicable. Ergon Energy has prepared the Opex line items in a consistent manner to that of Opex reported in response to the AER's 2012-2015 Annual Reporting Requirements.
B	Ergon Energy has sourced the data used to populate template 3, table 3.2.1 from the Ellipse General Ledger which retrospectively (2005/06 – 2009/10) adopted the current CAM approach for regulatory reporting and the AER Annual Reporting RINs for the relevant year. For 2010/11, 2011/12 and 2012/13 data was sourced from the relevant Performance RINs which were also based upon the Ellipse General Ledger the exception this was ACS metering were this had not been separately reported in the Annual Performance RIN and accordingly the reported values was directly obtained from the Ellipse General Ledger.
C	For all years, Ergon Energy extracted the Ellipse Trial Balance for each respective financial year into an Access Database, created a Table containing mappings between the Ellipse Activities and product codes to the BM RIN Variables (DOPEX0201 - DOPEX0206) and a query was run to extract costs against relevant variables.
D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables, except Transmission Point Planning contained in template 3, table 3.2.1. Actual Information for DOPEX0206 Opex for transmission connection point planning is unavailable as costs are not captured at this level of disaggregation in the Ellipse General Ledger. Accordingly, Ergon Energy has provided 'Estimated Information' (as per the AER's defined term). An estimate of hours worked including on costs, and travel and accommodation costs

Variable		Addressing Basis of Preparation Requirements
		was made for the 2012/13 year. This was de-escalated using inflation based on the Australian Bureau of Statistics weighted average of 8 capital cities (Mar – Mar) for prior years. An overhead appointment was applied to arrive at the Opex only value.
	E	Ergon Energy notes that a material change has occurred in its cost allocation approach (affecting Capex and Opex) between the current (2010-15) and prior (2005-10) regulatory control periods. A new (still current) CAM was approved by the AER on 5 March 2009 replacing the prior approved Cost Allocation Method and Principles (CAMP) approved by the Jurisdictional regulator, the QCA on 2 May 2006 (1 July 2005 – 30 June 2010). Changes to the CAM (versus CAMP) include: ▪ In the years 2005/06 to 2009/10 overheads were allocated on the basis of labour dollars only. In the subsequent years overheads have been allocated in accordance with the AER approved CAM on a full-cost basis. ▪ Training costs for the years 2005/06 to 2009/10 were split between operating and capital in accordance with accounting standards. In the subsequent years training costs have been treated as an operating cost only; ▪ Street Lighting Services were reclassified as an Alternative Control Service under the CAM. The impact of the above changes can be seen by comparing template 3, tables 3.2.1 and 3.2.2.

Opex Consistency – Historical Cost Allocation

Template 3, table 3.2.2 requires Ergon Energy to report Opex in accordance with the AER's variables (as defined in Chapter 9 of the RIN Instructions and Definitions) and the Cost Allocation Approaches and reporting framework applied in the relevant Regulatory Years.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for 'Opex Consistency – Historical Cost Allocation'.

Table 4-9: Opex Consistency – Historical Cost Allocation

Variable		Addressing Basis of Preparation Requirements
DOPEX0201A-DOPEX0206A	A	AER variables DOPEX0201A – DOPEX0206A are considered mandatory and have been populated by Ergon Energy. Opex has been reported in accordance with the Benchmarking RIN variables. Ergon Energy confirms, as required by the AER in Box 5, *Reporting Framework – Table 3.2.2 Opex Consistency - Historical Cost Allocation Approaches* in its RIN Instructions and Definitions that Opex has been prepared for all Regulatory Years in accordance with Ergon Energy approved CAM (AER) or CAMP (QCA) in effect for the individual regulatory year. Similarly, the principles and approach or requirements pertaining to the prevailing Annual Reporting Requirements (AER defined term) relevant to each individual year

Variable	Addressing Basis of Preparation Requirements
	were applied in reporting Opex for that Regulatory Year. As Ergon Energy does not currently own, control or operate any dual-function assets, there is no associated Opex to report. Ergon Energy does not have any subsidiaries which provide operating and maintenance services to the DNSP; therefore reporting of margins is inapplicable.
B	Ergon Energy has sourced the majority of the data used to populate template 3, table 3.2.2 from the previously audited Ellipse trial balances which reconcile to the QCA RRS or the AER's Annual Reporting RINs for the relevant year. The exception to this was estimated cost of transmission connection point planning. This was estimated based upon the number of hours spent on this task plus travel and other incidental costs.
C	Each variable in the Table has been populated by extracting data from the previously audited Ellipse trial balances which have been mapped to the relevant BM RIN categories or the AER Annual Reporting RINS for the relevant year. The exception to this was estimated cost of transmission connection point planning. This was estimated based upon the number of hours spent on this task plus travel and other incidental costs. The reported values for public lighting were extracted from the relevant audited Performance RINs which were also based upon the audited Ellipse General Ledger.
D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 3, table 3.2.2 (with the exception of DOPEX0206A). Actual Information for DOPEX0206A Opex for transmission connection point planning is unavailable as costs are not captured at this level of disaggregation in the Ellipse General Ledger. Accordingly, Ergon Energy has provided 'Estimated Information' (as per the AER's defined term). An estimate of hours worked including on costs, and travel and accommodation costs was made for the 2012/13 year. This was de-escalated using inflation based on the Australian Bureau of Statistics weighted average of 8 capital cities (Mar – Mar) for prior years. An overhead appointment was applied to arrive at the Opex only value.
E	Refer response to minimum requirement E for Current Opex Categories and Cost Allocations above, which noted changes in historical cost allocation approaches impacting both Capex and Opex.

4.2.4.3 Provisions

The AER requires Ergon Energy to report, for all Regulatory Years, financial information on provisions for SCS in accordance with the requirements of the Cost Allocation Approach and the Regulatory Accounting Statements that were in effect for the relevant Regulatory Year.

Ergon Energy is required to report financial information for each of its individual provisions. That is, each account which records a specific present liability of an entity to another entity.

The Opex and Capex components of each provision are required to be separately reported in tables provided in Template 3.

Ergon Energy Provisions

Ergon Energy notes the following provisions have been reported (additional rows inserted as required):

- **Restructure:** The restructure provisions are an estimate of the amounts required to provide redundancy payments for employees.
- **Employee benefit on-cost provisions:** The employee benefit on-cost provisions consist of provisions for workers compensation and payroll tax on employee benefits.
- **Employee Entitlement Provisions** consist of Annual Leave, Long Service Leave, Vested Sick Leave, and Superannuation on employee entitlements.
- **Rehabilitation:** The rehabilitation provisions are an estimate of the amounts required to rehabilitate specifically identified sites occupied by Ergon Energy offices, substations, power stations and workshops.
- **Other**: Estimate of amounts required for other minor provisions.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for Template 3, 'Provisions' – Opex component.

Table 4-10: Provisions - Opex Component

Variable		Addressing Basis of Preparation Requirements
DOPEX0301A-DOPEX0306A **DOPEX0301B-DOPEX0306B** **DOPEX0301C-DOPEX0306C** **DOPEX0301D-DOPEX0306D** **DOPEX0301E-DOPEX0306E** **DOPEX0301F-DOPEX0306F** **DOPEX0301G-DOPEX0306G** **DOPEX0301H-DOPEX0306H**	A	AER variables DOPEX0301 – DOPEX0306 are considered mandatory and have been populated by Ergon Energy, relative to each Provision. Ergon Energy confirms, as required by the AER in Box 6, *Reporting Framework for Provisions* in its RIN Instructions and Definitions, that provisions are reported in accordance with the principles and policies within the Annual Reporting Requirements (AER defined term) for each Regulatory Year. Furthermore, financial information on provisions reconciles to the reported amounts for provisions in the annual Regulatory Information Notice or Regulatory Accounts information provided to the AER or QCA respectively.
	B	Ergon Energy has sourced the data from previously audited Annual Performance RIN, for the years 2010/11, 2011/12 and 2012/13. For the years 2005/06 to 2009/10, the source is the Ergon Energy general ledger. Provisions for Annual Leave, Long Service Leave, Vested Sick Leave, and Super on Employee Entitlements have not previously been disclosed as Provisions, but rather as 'Employee Entitlements'. Data has been sourced from the Ergon Energy general ledger.
	C	Restructure provision has been apportioned to regulated / non-regulated, and between service classifications based on asset base. Employee Benefits on-costs Provision and Other Provisions have been apportioned to regulated / non-regulated, and between service classifications based on asset base, then split between Opex and Capex using the Opex/Capex overhead split using QCA Approved CAMP for 2005/06-2009/10, and AER Approved CAM for 2010/11-2012/13.

Variable		Addressing Basis of Preparation Requirements
		For 2007/08 and 2008/09 the closing balance has been split, the yearly movement adjusted to ensure it balances. The 2009/10 opening balance equals the 2008/09 closing balance whilst the 2009/10 closing equals the 2010/11 opening, as taken from Ergon Energy's 2010/11 Annual Performance RIN. 2010/11 to 2012/13 splits were done in those particular years, so the numbers here are taken from the Provision schedules for each of the individual years. Rehabilitation Provision has been split as per classification of individual sites, i.e. regulated sites and non-regulated sites. If the movement in the Rehabilitation provision was due to Revalued assets, (i.e. posted to Asset Revaluation Reserve) this is classified as Other, i.e. neither Opex nor Capex. Vested Sick Leave is for control room employees only, therefore classified as SCS Opex. Provision for Annual Leave, Long Service Leave, & Super on Employee Entitlements has been apportioned to regulated/non-regulated, and between service classifications based on asset base, then split between Opex and Capex using the Opex/Capex overhead split using QCA Approved CAMP for 2005/06-2009/10, and AER Approved CAM for 2010/11-2012/13. For each year, the yearly movement has been split not the closing balance.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 3, table 3.3 – Opex component.
	E	Refer response to minimum requirement E for Current Opex Categories and Cost Allocations above, which noted changes in historical cost allocation approaches impacting both Capex and Opex. In meeting requirements for financial information on provisions to reconcile to the reported amounts for provisions in the Annual Reporting Requirements provided to the AER or QCA respectively, data has been prepared for all Regulatory Years in accordance with Ergon Energy's approved CAM (AER) or CAMP (QCA) as in effect for the individual Regulatory Year.

Capex Component

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for Template 3, 'Provisions' – Capex component.

Table 4-11: Provisions – Capex Component

Variable		Addressing Basis of Preparation Requirements
DOPEX0307A-DOPEX0312A **DOPEX0307B-DOPEX0312B** **DOPEX0307C-**	A	AER variables DOPEX0307 – DOPEX0312 are considered mandatory and have been populated by Ergon Energy relative to each provision. Additional rows for Provisions have been inserted as required. Ergon Energy confirms, as required by the AER in Box 6, *Reporting Framework for Provisions* in its Instructions and Definitions, that provisions are reported in accordance with the principles and policies within the Annual Reporting Requirements

Variable		Addressing Basis of Preparation Requirements
DOPEX0312C DOPEX0307D-DOPEX0312D DOPEX0307E-DOPEX0312E DOPEX0307F-DOPEX0312F DOPEX0307G-DOPEX0312G DOPEX0307H-DOPEX0312H		for each Regulatory Year. Furthermore, financial information on provisions reconciles to the reported amounts for provisions in the annual Regulatory Information Notice or Regulatory Accounts information provided to the AER or QCA respectively
	B	Ergon Energy has sourced the data from previously audited Annual Performance RIN for the years 2010/11, 2011/12 and 2012/13. For the years 2005/06 to 2009/10, the source is the Ergon Energy general ledger. Provisions for Annual Leave, Long Service Leave, Vested Sick Leave, and Super on Employee Entitlements have not previously been disclosed as Provisions, but rather as 'Employee Entitlements'. Data has been sourced from the Ergon Energy general ledger.
	C	Employee Benefits on-costs Provision and Other Provisions have been apportioned to regulated / non-regulated, and between service classifications based on asset base, then split between Opex and Capex using the Opex/Capex overhead split based on the QCA Approved CAMP for 2006-2010, and AER Approved CAM for 2011-2013. For 2008 and 2009 the closing balance has been split, the yearly movement adjusted to ensure it balances. For 2010, the opening balance is equal to the 2009 closing; the 2010 closing equals the 2011 opening, which was taken from the 2011 Performance RIN. 2011 to 2013 splits were done in those particular years, so the numbers here are taken from the Provision schedules in Ergon Energy's Annual Performance RIN for each of the individual years. Provision for Annual Leave, Long Service Leave, & Super on Employee Entitlements has been apportioned to regulated/non-regulated, and between service classifications based on asset base, then split between Opex and Capex using the Opex/Capex overhead split using QCA Approved CAMP for 2005/06-2009/10, and AER Approved CAM for 2010/11-2012/13. For each year, the yearly movement has been split not the closing balance.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 3, table 3.3 – Capex component.
	E	Refer response to minimum requirement E for Current Opex Categories and Cost Allocations above, which noted changes in historical cost allocation approaches impacting both Capex and Opex. In meeting requirements for financial information on provisions to reconcile to the reported amounts for provisions in the Annual Reporting Requirements provided to the AER or QCA respectively, data has been prepared for all Regulatory Years in accordance with Ergon Energy's approved CAM (AER) or CAMP (QCA) as in effect for the individual Regulatory Year.

4.2.4.4 Opex for High Voltage Customers

AER requires Ergon Energy to report the amount of Opex that it would have incurred had it been responsible for operating and maintaining the electricity Distribution Transformers that are owned by its high voltage customers.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for Template 3, 'Opex for High Voltage Customers'.

Table 4-12: Opex for High Voltage Customers

Variable		Addressing Basis of Preparation Requirements
DOPEX0401	A	DOPEX0401 is considered a mandatory variable and has been populated by Ergon Energy. It is noted that data in this table will not reconcile to information reported in response to Annual Reporting RIN's provided by Ergon Energy, as we do not capture costs in relation to distribution transformers owned by HV customers.
	B	Ergon Energy has sourced the data from Ellipse using Artemis 7 (SPARQs and Ergon Energy's Programme Management Tool) for actual costs for distribution maintenance for the years 2010/11 – 2012/13. For prior years the cost per MVA was de-escalated by CPI based on the March – March inflation rate from the ABS website for the weighted average of 8 capital cities. Variable DPA0502: Distribution transformer capacity owned by High Voltage Customers (MVA) was also used in arriving at an estimate (refer to section 4.2.7.2: Transformer Capacities Variables for a detailed explanation of the source for the data).
	C	Refer response to minimum requirement D below, which details the methodologies applied to provide Estimated Information including assumptions made.
	D	Actual Information for DOPEX0401 is unavailable. Accordingly, Ergon Energy has provided 'Estimated Information' (as per the AER's defined term) in relation to DOPEX0401 - Opex for High Voltage Customers. As required by the AER's instructions and definitions, DOPEX0401 was estimated based on the Opex Ergon Energy incurs for operating similar Megavolts-ampere (MVA) capacity Distribution Transformers within its own network. . The total annual cost of maintenance for distribution transformers (owned by Ergon Energy) was obtained for three years 2010/11, 2011/12, 2012/13 from Artemis 7. The total annual maintenance cost for distribution transformers owned by Ergon Energy was then multiplied by the percentage of Ergon Energy's distribution transformers greater than 500kVA capacity to obtain the annual maintenance cost of >500kVA transformers owned by Ergon Energy. The annual maintenance cost of the >500kVA transformers owned by Ergon Energy was then divided by the total MVA of the >500kVA transformers owned by Ergon Energy to give the per-MVA cost of maintaining Ergon Energy owned transformers >500kVA . There are no customers below 500kVA and connection policies have freed up conditions regarding HV customers such that some are now connected with as low as 500kVA capacity requirements, versus a previous minimum of 1,000kVA, making 500kVA a suitable delineating point. Therefore, the cost of maintenance for Ergon Energy's transformers above 500kVA was calculated. HV Transformer capacity owned by Customers (MVA) was multiplied by the per-MVA cost ($/MVA) of maintaining Ergon Energy owned transformers > 500kVA to provide an estimate of the cost of maintaining the distribution transformers owned by customers. Base year for Distribution

Variable		Addressing Basis of Preparation Requirements
		Transformer numbers is 2013/14.
	E	Changes in accounting policies adopted by Ergon Energy are not relevant to costs incurred in relation to external customers, other than in relation to components of data being utilised for the estimate provided (that is, Opex). Costs have been presented on a current cost approach basis in that it is consistent with the most recent Annual Reporting Requirements and the 2012/13 allocation of costs in the CAM

4.2.5 Assets (Regulatory Asset Base)

The AER requires data in relation to the opening value of assets, depreciation, the opportunity cost of funds used to purchase assets and capital gains to calculate an ‘Annual User Cost of Capital’ (AUCC) for each capital input category employed the economic benchmarking model. This in turn requires Ergon Energy to allocate Regulatory Asset Base (RAB) assets that provide Standard Control Services and Alternative Control Services into the specified capital input categories.

Further, the AER is requesting RAB assets that provide Standard Control Services to be further disaggregated into a Network Services RAB. This is to align with the AER’s definition of Network Services set out in Appendix B, Instructions and Definitions, and the categories of services (and assets) that will be used to benchmark DNSPs

A ‘Standard Approach’ as described in section 4.1.1 of Appendix B must be followed, however an Optional Additional Approach may also be allowed (and provided as a separate excel sheet) where Ergon Energy believes it has sufficient information to provide a consistent RAB disaggregation that better reflects the values of its assets.

Ergon Energy must report RAB values in accordance with Box 7 - *Assets (RAB) Financial Reporting Framework* in Appendix B, Instructions and Definitions.

Where a RAB or RAB equivalent has been approved by the AER for ACS, Ergon Energy must report RAB values, or alternatively, report ‘0’ in the cells.

4.2.5.1 Regulatory Asset Base Values

Template 4, table 4.1 (Regulatory Asset Base Values) requires Ergon Energy to report totals for RAB Financial Information for all years, across Network Services, Standard Control Services and Alternative Control Services.

Ergon Energy notes that variables DRAB0101 through DRAB0107 in table 4.1 represent RAB Financial Information for the total asset base. The RAB Financial Information for the total asset base is then further disaggregated into the lower level RAB Asset Categories for each category of service (SCS, ACS and Network Services) in table 4.2.

As Ergon Energy has addressed the minimum Basis of Preparation requirements at the lower level RAB Asset Categories (in section 4.2.5.2 below), it is implicit that Ergon Energy has also addressed the minimum requirements for template 4, table 4.1. This is because all of the RAB values set out in template 4 have been calculated using a common Roll Forward Model for each category of service (SCS, ACS and Network

Services). As a result, the RAB values reported for the total asset base in table 4.1 will be consistent with the RAB values reported at the lower level RAB Asset Categories in table 4.2 for each category of service.

4.2.5.2 Asset Value Roll forward

Template 4, table 4.2 requires Ergon Energy to report RAB Financial Information by RAB Asset categories as per the definitions provided in Chapter 9 of the RIN Information and Definitions.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for the RAB 'Annual Value Roll Forward'.

Table 4-13: Asset Value Roll Forward - Standard Control and Alternative Control Services

Variable	Addressing Basis of Preparation Requirements
DRAB0101-DRAB0107 A **DRAB201-DRAB1107** **DRAB1201-DRAB1210**	Ergon Energy confirms, as required by the AER in Box 7, *Assets (RAB) Financial Reporting Framework* in in Appendix B, Instructions and Definitions, that ▪ RAB financial information for Standard Control and Alternative Control Services reconciles to decisions the AER has made in relation to RAB values for these services through the 2010-15 Ergon Energy Distribution Determination; and ▪ Where forecast values were used in relation to a decision on RAB values (in the 2010-15 Distribution Determination), these amounts have been replaced with actual values which reconcile to amounts reported in Annual Financial Statements (i.e. additions for the last year of the previous regulatory period. Ergon Energy has adopted the *Standard Approach*, with *Direct Attribution to the AER's economic benchmarking RAB Asset Classes*, as described in section 4.1.1 of Appendix B, Instructions and Definitions. For some non-system assets to the AER's 'other long life assets' and 'other short life asset categories' their categorisation has been ascertained by using additional Ellipse source system extracts (additions report). This is discussed further in Table 4-13, section C below. ▪ RAB Asset Financial Information for remaining asset classes has been directly allocated into RAB Asset categories in accordance with definitions provided in chapter 9 of the Appendix B, Instructions and Definitions (Refer to Section C below). RAB values for each of the RAB Asset categories are inclusive of Capital Contributions. Total capital contributions for each relevant regulatory year are provided at DRAB13. ▪ Ergon Energy currently does not own, control or operate any Dual Function Assets. ▪ Although Variable Codes DRAB0801 – DRAB0807 in relation to RAB Asset 'Easements' are shaded orange, to allow for blacked out data input, these cells have been populated. Ergon Energy has the ability to report Easements, and necessarily they are not included in the remaining categories. ▪ In accordance with the instructions and definitions, Ergon Energy has only included RAB values for those services where the AER has approved a RAB or RAB equivalent. Therefore, for Alternative Control Services, Ergon Energy has only reported RAB assets that provide Alternative Control Street lighting Services,

Variable		Addressing Basis of Preparation Requirements
		consistent with the classification of service, and RAB that was approved for this category of service in Ergon Energy's 2010-15 Distribution Determination. No RABs have been approved for any of Ergon Energy's other categories of Alternative Control Services (Quoted and Fee Based Services).
	B	Standard Control Services (including street lighting services up to and including 2008/09) for the period 2005/06 to 2008/09, reflect actual values sourced from the AER-approved RAB roll-forward model used in the AER's 2010-15 Final Distribution Determination for Ergon Energy. Standard Control Services (including street lighting services) for 2009-10, have been updated to reflect actual values sourced from the QCA RRS. No RAB was approved for any of Ergon Energy's Alternative Control Services (or equivalent Alternative Control Services) for the period 2005/06 to 2009/10.For the period 2010/11 to 2012/13 inclusive, annual Standard Control Services values (excluding street lighting services) are sourced from the associated AER Annual Performance RIN's provided by Ergon Energy and accepted by the AER. From 2010/11, the AER reclassified Ergon Energy's street lighting services as an Alternative Control Service. Data for Alternative Control Services (street lighting) for the period 2010/11 to 2012/13 inclusive are sourced from the annual Reporting Information Notices provided by Ergon Energy accepted by the AER.
	C	Asset information reflects actual data sourced from either the AER approved RAB roll-forward model, QCA RRS or annual Reporting Information Notices (Annual Performance RIN's). Ergon Energy asset categories (as reported in the roll forward model and Annual Performance RIN's) have been directly mapped to the required economic benchmarking RAB asset categories, with the exception of some non-network asset categories (see below). For some non-network asset categories (buildings, motor vehicles and plant and equipment), the AER definitions require Ergon Energy to split assets between short and long-life assets categories. Ergon Energy does not report data on this disaggregated basis. However, asset additions are readily determined from the asset register along with their lives. This information was used to apportion the relevant opening balances, additions and disposals to the required short and long-life categories ▪ Ergon Energy has apportioned total buildings, motor vehicles and plant & equipment attributable to short and long life categories on the basis of asset addition for each asset. Asset additions are readily determined from the asset register along with the associated asset lives. With motor vehicles (as an example) heavy vehicles and a % of total vehicle additions was determined. This was then used to split total vehicle Capex between short and long lives. The same process was used for buildings and for plant & equipment. RAB disposals are allocated between short and long lived assets based on asset additions to these categories. ▪ Roll-forward RAB values for each year of the 2005/06 to 2012/13 period are determined using the AER-approved RAB roll-forward model used in the AER's 2010-

Variable		Addressing Basis of Preparation Requirements
		15 Final Distribution Determination for Ergon Energy.
	D	Ergon Energy has provided ‘Actual Information’ (as per the AER’s defined term).
	E	Refer response to minimum requirement E for Current Opex Categories and Cost Allocations above, which noted changes in historical cost allocation approaches impacting both Capex and Opex.

Table 4-14: Annual Value Roll Forward – Network Services

Variable		Addressing Basis of Preparation Requirements
DRAB0101-DRAB0107 **DRAB201-DRAB1107** **DRAB1201-DRAB1210**	A	Ergon Energy has prepared the information for the Network Services RAB in accordance with the definition of Network Services set out in Appendix B, Instructions and Definitions. Further detail on how the information provided by Ergon Energy is consistent with the requirements and definitions of Network Services is discussed below
	B	As defined by the AER for the purposes of the Economic Benchmarking RIN, Network Services are a subset of Standard Control Services excluding Connection Services, Metering Services, Fee Based and Quoted Services and Street Lighting Services. In the case of Ergon Energy, consistent with the AER’s definition of Network Services, we assume it is also necessary to exclude gifted assets (since these are all related to connection services) and also any assets included in the Network Services category that are not funded by Ergon Energy i.e. Network Services funded via capital contributions. Standard Control Services data is sourced from actual data (as discussed in the previous section above).Connection Services data is captured within the Ergon Energy “Customer Initiated Capital Works” (CICW) expenditure category. Specifically, CICW expenditure includes: ▪ All new shared network assets associated with new small and large customer connections, including new subdivisions; ▪ New connections for Standard Asset Customers; and ▪ Testing and commissioning of all new shared network assets and connection assets. Actual CICW data for the period 2005/06 to 2009/10 is available from the audited annual Regulatory Accounts provided to the QCA. For the period 2010/11 to 2012/13 inclusive, the annual CICW values are sourced from the associated annual Reporting Information Notices provided by Ergon Energy and accepted by the AER. As indicated above, CICW expenditure incorporates a portion of shared network expenditure (either funded by Ergon Energy or funded via capital contributions). To be consistent with the AER’s definition of Network Services, we assume it is necessary for any Ergon Energy-funded shared network to be reported in the Network Services category, but any gifted assets and shared network not funded by Ergon Energy to be excluded. In order to derive the net value of shared network expenditure to be included in Network Services (and hence, the value of CICW expenditure to be removed from

Variable	Addressing Basis of Preparation Requirements
	the SCS asset additions), it is necessary to: ▪ identify the total amount of CICW expenditure related to the shared network; ▪ identify that portion of the CICW shared network expenditure that is not funded by Ergon Energy (i.e. capital contributions associated with the shared network) so that only this portion is removed from Network Services; and ▪ identify the amount of gifted assets (i.e. which relate to connection assets) The net result of the above (i.e. total CICW expenditure related to connection assets (i.e. not shared) plus customer capital contributions to the shared network, plus gifted assets) represents that portion of CICW expenditure that is required to be removed from SCS asset additions in order to determine the amount attributable to Network Services. Actual data associated with Metering Services and Street Lighting Services (to be removed from Standard Control Services data) is available from the AER-approved RAB roll-forward model used in the 2010-15 Ergon Energy Distribution Determination, the QCA 2009/10 Regulatory Reporting Statements and the Annual Performance Reporting Information Notices provided by Ergon Energy and accepted by the AER. No adjustment is necessary in relation to Fee Based and Quoted Services since this expenditure is already excluded from the Standard Control Services data. Gifted assets data is available from audited annual Regulatory Accounts provided to the QCA. For the period 2010/11 to 2012/13 inclusive, the value of gifted assets is sourced from the Ellipse General Ledger, as associated AER Annual Performance RIN's provided by Ergon Energy and accepted by the AER reported the aggregated amounts for cash and gifted contributions. Capital contributions data is available from audited annual Regulatory Accounts provided to the QCA and the associated AER Annual Performance RIN's provided by Ergon Energy and accepted by the AER. Network Services funded via capital contributions are required to be estimated.
C	To be consistent with the AER's definition of Network Services expenditure related to Metering Services, and Street Lighting Services was removed from the Standard Control Services data. Adjustments to annual CICW expenditure were made to determine the net amount of shared network expenditure to remain in the Network Services data (and hence, the amount of expenditure required to be removed from SCS asset additions for connection assets, gifted assets and shared network assets funded via capital contributions) The resultant CICW expenditure to be excluded from the Standard Control Services asset additions category was attributed to the AER individual asset categories and removed from the Network Services RAB calculations The remaining expenditure represents the annual additions to the Network Services category by asset type. An estimate of the opening Network Services RAB value was then determined using

Variable		Addressing Basis of Preparation Requirements
		the estimation method outlined in section D below.. The opening Network Services RAB was rolled-forward (by the annual additions to Network Services) consistent with the AER's roll-forward process to derive the Network Services RAB for each of the required reporting years.
	D	Ergon Energy does not separately identify expenditure or assets related to Network Services. While it is possible to make some adjustments to the Standard Control Services data to identify a partial measure of the Network Services component e.g. remove metering assets, gifted assets etc. Some estimation is required to derive the complete Network Services data. In particular, it is necessary to identify the portion of CICW that relates to connection services and is therefore required to be excluded from the Standard Control Services data in order to derive an estimate of Network Services additions. In order to do so, it is necessary to estimate the: ▪ portion of annual CICW expenditure that relates to the shared network; and ▪ portion of the CICW shared network expenditure that is not funded by Ergon Energy i.e. shared network provided via capital contributions. This estimation process, including how the resultant values are attributed to the AER's asset categories and the associated Network Services opening RAB value and RAB roll-forward process is outlined below. ***Estimating the portion of CICW that relates to Network Services (i.e. the shared network).*** ▪ Ergon Energy does not separately identify the proportion of CICW expenditure attributable to Network Services. As a consequence, it is necessary to develop an estimate. ▪ As part of the 2010-15 regulatory determination process, Ergon Energy conducted analysis (including sampling a range of CICW projects conducted during 2007/08) in order to estimate the associated shared network component associated with the following customer categories: o Commercial and Industrial (small customers); o Commercial and Industrial (large customers); o Domestic and Rural (small customers); and o Subdivisions (small customers). ▪ The analysis identified the portion of expenditure in each of the above customer categories attributable to the shared network. This analysis was used as the basis for the associated expenditure forecasts for the 2010-15 regulatory control period. ▪ The analysis, contained in Ergon Energy (2009), "Forecasts – Customer Initiated Capital Works – Standard Control Services", June, was provided to the AER as part of Ergon Energy's 2010-15 Regulatory Proposal. ▪ Inquiries were made with subject matter experts across Ergon Energy in February 2014 to determine whether any alternative approach was available for estimating proportional expenditure attributable to shared network on a historical basis. It was

Variable	Addressing Basis of Preparation Requirements
	confirmed following these inquiries, that no other methodology or reporting arrangement existed and on this basis the methodology outlined in this basis of preparation was used for estimation. Ergon Energy has used its best endeavours to provide Estimated Information in this regard, on the basis that: o Actual data relating to the contribution to shared network costs was not previously reported in the Ergon Energy systems. o The 2007/08 sample year is within the historic data series required to be reported in the Benchmarking RIN; o The methodology was derived by subject matter experts as part of the 2010-15 regulatory submission and subsequently reviewed by subject matter experts within Ergon Energy, who confirmed that the approach and subsequent results remain valid; and o The methodology is consistent with the approach used to support expenditure forecasts as part of Ergon Energy's 2010-15 regulatory determination. ***Estimating the portion of shared network CICW expenditure that was funded via capital contributions*** Ergon Energy's capital contribution policy is set out in the AER approved, Ergon Energy Capital Contributions Policy (2005). The policy sets out circumstances in which a capital contribution may be required and details how the capital contribution to be charged to a customer is calculated. In particular: ▪ Contributions may be required from developers of subdivisions and other small CICW customers (Standard Asset Customers). ▪ Ergon Energy allows for contributions to be provided via cash contributions i.e. Ergon Energy undertakes the required work, or gifted i.e. the works are undertaken by the customer and the assets that are built gifted to Ergon Energy. Note: all gifted assets are assumed to relate to specific connection assets (rather than any shared network), since only Ergon Energy can undertake work on the shared network. Therefore, all gifted assets are excluded from the Network Services category. It is necessary to determine the value of developer and other customer cash capital contributions attributable to the shared network. *Developer capital contributions attributable to the shared network* ▪ For developer cash contributions, Ergon Energy's Capital Contribution Policy requires developers to fully fund any required shared network works. Ergon Energy has not previously captured the breakdown of costs to identify the shared network components of developer contributions, and accurate data is not available. ▪ As a result, Ergon Energy has approximated the proportion of developer contributions attributable to shared network works based on a sample of data. As discussed previously, as part of the 2010-15 regulatory determination process, Ergon Energy sampled a range of subdivision projects conducted during 2007/08 in

Variable	Addressing Basis of Preparation Requirements
	order to estimate the associated shared network component. The analysis concluded that approximately 31% of subdivision expenditure during the year could be attributed to the shared network ("headworks"). ▪ Internal discussions held with subject matter experts in the Asset Management division of Ergon Energy confirm that the proportion of expenditure attributable to the shared network remains valid for use in the current AER Benchmarking RIN exercise. ▪ Consequently, Ergon Energy has applied this percentage to estimated subdivision cash contributions to derive the associated annual subdivision contribution to the shared network (see details below). ▪ In relation to the proportion of developer cash contributions attributable to shared network, Ergon Energy considers that in employing the above approach it has used its best endeavours to provide Estimated Information, on the basis that: o Actual data relating to the contribution to shared network costs was not previously reported in the Ergon Energy systems; o The 2007/08 sample year is within the historic data series required to be reported in the Benchmarking RIN; o The methodology was derived by subject matter experts at the time and subsequently reviewed by subject matter experts within Ergon Energy, who confirmed that the approach and subsequent results remain valid; and o The methodology is consistent with the approach used to support expenditure forecasts as part of Ergon Energy's 2010-15 regulatory determination. *Other customer capital contributions attributable to the shared network* ▪ For other customer cash contributions, Ergon Energy's Capital Contribution Policy requires customers to make a contribution to shared network costs. The contribution differs depending on the customer's location (East, West or Mount Isa). Ergon Energy has not previously captured the breakdown of costs to identify the shared network components of other customer cash contributions, and accurate data is not available. ▪ As a result, Ergon Energy has approximated the proportion of other customer cash contributions attributable to shared network works based on a sample of data. ▪ A sample of individual customer price book applications provided during 2012/13 was examined to determine the value of any capital contribution attributable to the shared network. ▪ The shared network values were derived on the basis of the capital contribution formula and associated shared network proportions contained in Ergon Energy's Capital Contributions Policy. ▪ The sample outcomes were weighted by the number of customers in each of the three regions (East, West and Mount Isa) in 2012/13 to derive the average proportion of other customer cash contributions attributable to the shared network.

Variable	Addressing Basis of Preparation Requirements
	▪ Ergon Energy applied this percentage (9.1%) to an estimate of other customer cash contributions to derive the associated annual other customer contribution to the shared network. ▪ Ergon Energy consider that the above approach represents its best endeavours to provide Estimated Information for other customer cash contributions attributable to shared network on the basis that: o Actual data relating to the contribution to shared network costs was not previously reported in the Ergon Energy systems; o The 2012/13 sample provides a randomly selected range of projects covering each of the three Ergon Energy regions; and o There is no reason to suspect that the 2012/13 sample year is not a representative year. *Estimating the proportion of total cash customer contributions attributable to subdivisions/other customers* ▪ Ergon Energy does not provide cash contributions separated between subdivision and other customer contributions in an accessible format. Estimates of subdivision and other customer cash capital contributions were therefore approximated based on the allocation of cash contributions in 2007/08 reported in Ergon Energy (2009), "Forecasts – Customer Initiated Capital Works – Standard Control Services", June. As discussed above, this document was previously provided to the AER as part of Ergon Energy's 2010-15 regulatory submission. ▪ This analysis indicates that approximately 92% of total cash contributions in 2007/08 was estimated to be related to subdivisions, with the remaining 8% attributable to other customers. ▪ In the absence of actual data, these proportions have been applied to the total value of actual cash capital contributions for each year of the 2005/06 to 2012/13 period to determine an estimate of the value of cash contributions attributable to subdivisions and other customers. ▪ Ergon Energy considers that this approach represents its best endeavours to provide Estimated Information in relation to subdivision/other customer capital contributions on the basis that: o Actual data relating to the composition of cash contributions was not previously reported in the Ergon Energy systems o The 2007/08 sample year is within the historic data series required to be reported in the Benchmarking RIN; o The methodology was derived by subject matter experts at the time; and o The methodology is consistent with the approach used to support expenditure forecasts as part of Ergon Energy's 2010-15 regulatory determination. The above process results in an annual estimate of the amount of CICW additions related to connection services (i.e. not shared network). These additions are required to

Variable	Addressing Basis of Preparation Requirements
	be removed from the Standard Control Services additions in order to derive an estimate of Network Services additions. ***Assigning the value of the connection services portion of CICW expenditure to asset categories*** Once the connection services portion of annual CICW expenditure is determined (i.e. the outcome of the above estimates), it is necessary to attribute these annual values to the AER asset categories. ▪ Ergon Energy has assigned the connection services portion of annual CICW expenditure to asset classes based on an apportionment process. This is based on the percentage split of asset categories for CICW expenditure from the Ellipse Project Accounting module. ▪ The Project Accounting module provides a detailed breakdown of annual capital expenditure by type of expenditure. It is then possible to map this expenditure to Ergon Energy's asset register and to the AER asset categories. Using this process, Ergon Energy has attributed annual CICW expenditure to the AER asset categories for each of the three years 2010/11 to 2012/13. The average of these three years for each of the asset categories has then been used to attribute the connection services portion of CICW expenditure to the AER categories for the 2005/06 to 2012/13 reporting period. o Ergon Energy has adopted this allocation process in its AER Annual Performance RIN's provided by Ergon Energy and accepted by the AER for the past three years (2010/11 to 2012/13). Ergon Energy considers that this represents the best approach available on the basis that: o No actual information is available in relation to the CICW connection services by asset type; o The breakdown of CICW capital expenditure by asset type is expected to provide a reasonable proxy of the distribution of connection services expenditure; and o The attribution process has been used by Ergon Energy in developing AER Annual Performance RIN's provided by Ergon Energy and accepted by the AER. The remaining value of Standard Control Services additions by asset class effectively represents the annual Network Services additions. **Determining the Network Services Opening RAB as at 1 July 2005** In order to determine the Network Services RAB roll-forward values for the 2005/06 to 2012/13 period, it is necessary to determine the opening Network Services RAB as at 1 July 2005. ▪ In order to do so, Ergon Energy has adjusted the AER approved opening RAB for Standard Control Services (as at 1 July 2005) provided as part of the 2010-15 regulatory determination process to remove connection assets, metering assets and cash contributions toward shared network costs (note, street lighting assets

Variable		Addressing Basis of Preparation Requirements
		and gifted assets were not included in the AER's opening RAB value). ▪ Metering assets were identified as a separate asset category as part of the opening Standard Control Services RAB. Our approach was to remove this asset category from the opening RAB. ▪ Connection assets are not separately identified in the opening RAB. However, Ergon Energy identifies a notional value of customer specific connection assets as part of its Distributed Cost of Service (DCOS) model used to generate annual distribution prices. Accordingly, this value is used as a proxy for the value of connection services in the opening Standard Control Services RAB. Ergon Energy considers it has used its best endeavours to provide Estimated Information in this regard, on the basis that on the basis that: o Actual connection assets are not separately identified in the opening Standard Control Services RAB; and o The DCOS model from which the connection asset proportions are determined is used as part of Ergon Energy's annual Pricing Proposal, which is approved by the AER. ▪ In addition, some of the assets associated with Network Services may have been contributed via capital contributions (from developers and other customers). The value of shared asset capital contributions is not separately identified in Ergon Energy's records. However, in the absence of better information, the portion of contributed assets associated with the shared network is expected to be insignificant as a portion of the total RAB and is, therefore assumed to be zero. Ergon Energy considers it has used its best endeavours to provide Estimated Information in this regard, on the basis that: o Actual shared network contributions associated with capital contributions are not separately identified by Ergon Energy; and o Capital contributions historically represent a very minor portion of the total RAB and the shared network contribution represents a very minor portion of capital contributions. ***Network Services RAB roll-forward*** ▪ Once the opening Network Services RAB and additions to the Network Services RAB have been determined (as above), it is necessary to roll-forward the Network Services RAB for each year of the 2005/06 to 2012/13 reporting period. ▪ Ergon Energy has adopted the AER's roll-forward model to determine the Network Services RAB for each year of the RIN reporting period.
	E	Refer response to minimum requirement E for Current Opex Categories and Cost Allocations above, which noted changes in historical cost allocation approaches impacting both Capex and Opex.

4.2.5.3 Total Disaggregated RAB Asset Values

Template 4, table 4.3 requires Ergon Energy to report Average RAB Asset values that have been disaggregated into the asset categories identified. The values must be calculated as the average of the opening and closing RAB values for the relevant Regulatory Year for each of the RAB Assets and should be directly reconcilable to the opening and closing values in template 4, table 4.2 for the relevant categories.

In addressing the minimum Basis of Preparation requirements for variables for 'Total Disaggregated RAB Asset Values', Ergon Energy notes that for the relevant Regulatory Year, variables DRAB01201 through DRAB01210 represent the average of the opening and closing RAB values for each of the Asset Category values reported in template 4 table 4.2, and are therefore implicitly addressed in responses contained in comments made in section 4.2.5.2 above in relation to Asset Value Roll Forward (by service).

Capital Contributions

Capital Contributions are required to be reported in template 4 Assets (RAB), including as a separate entry at DRAB13. In addressing the minimum Basis of Preparation requirements in relation to DRAB13 Capital Contributions, Ergon Energy makes the following comments.

Table 4-15: Total disaggregated RAB asset values – Capital contributions

Variable		Addressing Basis of Preparation Requirements
DRAB13	A	As all data entry fields are shaded yellow, indicating mandatory data input fields, all cells have been populated. RAB values for each of the RAB Asset categories in the worksheet are inclusive of Capital Contributions. Ergon Energy notes the value provided at DRAB13 is the total value, for "estimated value of capital contributions or contributed assets' for each relevant regulatory year. Refer above comments section 4.2.5.2 above in relation to Asset Value Roll Forward (by service) with regards to splitting between Network Services, Standard Control Services and Alternative Control Services.
	B	Data used to populate this table was extracted from previously audited Regulatory Reporting Statements and RINs.
	C	For the years 2010/11, 2011/12 and 2012/13 the Ergon Energy Performance RIN and general ledger separately reported/recorded the capital contribution revenue earned for Standard Control Services and Alternative Control Services. In the previous years all capital contributions were reported as a DUOS service in the QCA Regulatory Reporting Statements.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term).
	E	No accounting policies adopted by Ergon Energy have impacted on capital contributions received.

4.2.5.4 Asset Lives

The AER also requires Ergon Energy to report asset lives in relation to all RAB Assets, including estimated service live of new assets, and estimated residual service lives.

Where RAB Assets categories comprise of a number of assets, asset lives for the whole category must be calculated by weighting the lives of individual assets within that category, using weightings in order of preference stipulated in the AER's Instructions and Definitions (page 27). The RAB is the AER's preferred asset value measure for weighting lives, but replacement costs is considered an acceptable proxy if disaggregation of the RAB to the relevant level is not possible (and capacity shares are then a further proxy to replacement cost shares).

Asset Lives – Estimated Service Life of New Assets

Template 4, table 4.4.1 requires Ergon Energy to report the current expected service life of new assets, where:

- new assets are assets installed in the most recent regulatory reporting year; and
- the expected service life of new assets is the estimated period after installation of a new asset during which the asset will be capable of delivering the same effective service as it could at its installation date, which may not align with the asset's financial or tax life.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for Estimated Service Lives of New Assets.

Table 4-16: Asset Lives – Estimated Service Life of New Assets

Variable		Addressing Basis of Preparation Requirements
DRAB1401-DRAB1409	A	As all data entry fields are considered mandatory data input fields and have been populated. Asset lives reported, are estimated service lives of new assets installed in the relevant regulatory reporting year.
	B	Data was sourced from Ergon Energy's fixed asset register (FAR). Asset lives in the FAR are based upon engineering expectations and are reviewed on a regular basis.
	C	A mapping exercise was employed on data obtained from the fixed asset register whereby data was grouped into the RAB Asset categories required by the AER, in accordance with category definitions provided in Chapter 9. Where RAB Asset categories contained assets of differing lives a weighted average estimated life was calculated based on replacement cost using the formulae prescribed by the AER (equation 1, weighted average asset life calculation).
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 4, table 4.4.1.
	E	Asset lives reported are a non-financial data set, and accordingly this requirement is not applicable.

Asset Lives – Estimated Residual Service Life

Template 4, table 4.4.2 requires Ergon Energy to report estimated residual service lives of assets. A current estimation is required, of the weighted average remaining time expected that a RAB Asset category will deliver the same effective service as that asset class did at its installation date.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for Estimated Residual Service Lives.

Table 4-17: Asset Lives – Estimated Residual Service Life

Variable		Addressing Basis of Preparation Requirements
DRAB1501-DRAB1509	A	All data entry fields are shaded yellow, indicating mandatory data input fields and accordingly, have been populated. Asset lives reported, are estimated service lives of new assets installed in the relevant regulatory reporting year.
	B	Data was sourced from Ergon Energy's fixed asset register. Asset lives in the fixed asset register are based upon engineering expectations and are reviewed on a regular basis.
	C	A mapping exercise was employed on data obtained from the fixed asset register whereby data was grouped into the RAB Asset categories required by the AER, in accordance with category definitions provided in Chapter 9. Where RAB Asset categories contained assets of differing lives a weighted average estimated life based on replacement cost was calculated using the formulae prescribed by the AER (equation 1, weighted average asset life calculation).
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 4, table 4.4.2.
	E	Asset lives reported are a non-financial data set, and accordingly this requirement is not applicable.

4.2.6 Operational Data

The AER requires operational data to form the output measures for examining the efficiency with which DNSPs transform inputs into outputs. The data being collected is required to form 'output' measures, and includes energy delivery, customer numbers and maximum demand.

4.2.6.1 Energy Delivery

Specially, in template 5, table 5.1 the AER requires Ergon Energy to report Energy Delivered, being the amount of electricity transported out of its network in the relevant regulatory year (GWh). It is required to be energy delivered as metered or estimated at the customer charging locations rather than the import location from the Transmission Network Service Provider (TNSP).

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for Total Energy Delivery (DOPED01). Of note, DOPED01 represents the sum of energy delivered disaggregated by chargeable quantity (template table 5.1.1), by customer type or class (template table 5.1.4).

Table 4-18: Energy Delivery

Variable		Addressing Basis of Preparation Requirements
DOPED01	A	DOPED01 entry fields are shaded yellow, indicating mandatory data fields, and accordingly data for all regulatory years has been populated. Total Energy Delivered reported is the total metered or estimated energy delivered at the customer charging locations (rather than the import location from the TNSP).
	B	All data was sourced from a summary of monthly billing data files sourced from Netbill / FACOM via the STC and other Pricing files.
	C	Ergon Energy employed a methodology whereby kWh's for energy delivery were summated from monthly billing data files into annual totals. As the source file captured data in kWh's the results were converted to GWh's.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 5, table 5.1.1.
	E	Energy Delivered data is a non-financial data set, and accordingly this requirement is not applicable.

Energy Grouping – Delivery by Chargeable Quantity

Template 5, table 5.1.1 requires Ergon Energy to report energy delivered by chargeable quantity in accordance with the AER category breakdowns, as defined in Chapter 9 of Instructions and Definitions (Appendix B).

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables in relation to Energy delivered, grouped by chargeable quantity.

Table 4-19: Energy Grouping – Delivery by Chargeable Quantity

Variable		Addressing Basis of Preparation Requirements
DOPED0201-DOPED0206	A	Entry fields are shaded yellow indicating mandatory data fields, and accordingly data for all regulatory years has been populated. '*Energy Delivered where time of use is not a determinant'* (DOPED0201) relates only to energy delivered that was not charged for peak, shoulder or off-peak periods. Ergon Energy does not currently have network tariffs reflecting shoulder, on-peak, and off-peak time charging periods. Therefore, no disaggregation has been provided for time of use variables (DOPED0202 – DOPED0204) for the initial regulatory years...
	B	All data was sourced from a summary of monthly billing data files sourced from Netbill / FACOM via the STC and other Pricing files.
	C	Ergon Energy employed a methodology whereby kWh's for energy delivery were summated from monthly billing data files into annual totals and disaggregated into various categories. As the source file captured data in kWh's the results were converted to GWh's.

Variable		Addressing Basis of Preparation Requirements
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 5, table 5.1.1.
	E	Energy delivered data is a non-financial data set, and accordingly this requirement is not applicable.

Energy Received from TNSP and other DNSPs by Time of Receipt

Template 5, table 5.1.2 requires Ergon Energy to report energy input (received) into its network as measured at supply points from the TNSP and other DNSPs, by time of receipt as defined in Chapter 9 of Instructions and Definitions (Appendix B).

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for Energy Received.

Table 4-20: Energy Received from TNSP and Other DNSPs by time of Receipt

Variable		Addressing Basis of Preparation Requirements
DOPED0301-DOPED0304	A	All entry fields are shaded yellow indicating mandatory data fields, and have been populated for all regulatory years. '*Energy Received from TNSP and other DNSPs not included in the above categories'* (DOPED0304) relates only to energy received that was unable to be allocated to peak, shoulder or off-peak periods. In this regard, a wholesale time of use schedule no longer exists as relevant to Energy Received. Accordingly, no disaggregation has been provided for time of use variables (DOPED0301- DOPED0303).
	B	The source of the energy received data is National Energy Market (NEM) settlements data and Local Network Service Provider (LNSP) settlements metering. All meters are interrogated by the Australian Energy Market Operator (AEMO) accredited Meter Data Agents (MDAs) and passed to Ergon Energy LNSP in accordance with Chapter 7 of the NER. This data is automatically stored in the Ergon Energy DNSP central data repository (Statistical Metering Database (SMDB)) for analysis by the various Ergon Energy Asset Development planning groups. An aggregate load measurement point (LMP) was setup to cater for requirements. This aggregate LMP is updated when new and replacement measured data has been received from the MDAs. The aggregate definition is maintained, as is all Ergon Energy aggregate LMPs, in line with network asset changes. For example new Transmission Connection Points.
	C	Energy received in to the network from larger installations of embedded generation is recorded on a half hour basis. Energy delivered to the remote Mount Isa distribution network (which includes Cloncurry but not the 220kV connected Carpentaria Mineral Province mines) is included in this aggregation given derogations which include this as part of the AER-regulated Ergon Energy regulated network. There is no TNI in any AEMO documentation servicing this area of the network.

Variable		Addressing Basis of Preparation Requirements
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 5, table 5.1.2.
	E	Energy Received data is a non-financial data set, and accordingly this requirement is not applicable.

Energy Received from Embedded Generation by Time of Receipt

Template 5, table 5.1.3 requires Ergon Energy to report energy delivered into its network from (residential and non-residential) Embedded Generation by time of receipt, in accordance with the AER category breakdowns defined in Chapter 9 of Instructions and Definitions (Appendix B).

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables in Energy Received from Embedded Generation.

Table 4-21: Energy Received into DNSP system from Embedded Generation by Time of Receipt

Variable		Addressing Basis of Preparation Requirements
DOPED0401-DOPED0408	A	Data for variables DOPED0405 – DOPED0407 (for all regulatory years) and DOPED0408 (for regulatory years 2005/06-2007/08) in relation to energy received from Embedded Generation (residential) has not been recorded by Ergon Energy and accordingly, has been blacked out (not provided) as relevant. It was unnecessarily burdensome to estimate and it is illogical to enter '0'. All other entry fields shaded yellow indicating mandatory data fields, have been populated for all regulatory years. '*Energy Received from embedded generation not included in above categories from non-residential embedded generation* (DOPED0404) relates only to energy received that was unable to be allocated to peak, shoulder or off-peak periods. In this regard, a wholesale time of use schedule no longer exists as relevant to Energy Received. Accordingly, no disaggregation has been provided for time of use variables (DOPED0401- DOPED0403).
	B	Non-residential energy data was sourced by Ergon Energy from NEM settlements metering. All meters are interrogated by AEMO accredited MDAs and passed to Ergon Energy LNSP in accordance with Chapter 7 of the NER. This data is automatically stored in the Ergon Energy DNSP central data repository (SMDB) for analysis by the various Ergon Energy Asset Development planning groups. An aggregate load measurement point (LMP) was setup to cater for requirements. Only the energy received channel (B) is used in the aggregation. This aggregate LMP is up dated when new and replacement measured data has been received from the MDAs. The aggregate definition is maintained, as is all Ergon Energy aggregate LMPs, in line with new installations of embedded generation impacting on the Ergon Energy network. For regulatory years 2008/09-2012/13, DOPED0408 (residential) data was sourced from the Network Billing system (Netbill) using a Network Tariff Code specific to residential Embedded Generation. Data is inclusive of Tier 1 (EEQ) and Tier 2 (market

Variable		Addressing Basis of Preparation Requirements
		customer) premises.
	C	Energy received in to the network from larger installations of embedded generation is recorded on a half hour basis. DOPED0408 (residential) data represents the sum of all KWh recorded with a Network Tariff Code specific to Embedded Generation with a Residential Customer Classification Code, from the Netbill data source, and includes kWh recorded for Ergon Energy owned solar PV on residential customer (host roof) in relation to the Magnetic Island Solar Cities project.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 5, table 5.1.3.
	E	Energy Received data is a non-financial data set, and accordingly this requirement is not applicable.

Energy Grouping – Customer Type or Class

Template 5, table 5.1.4 requires Ergon Energy to report energy delivered in accordance with customer type or class categories as defined in the Information and Definitions at Appendix B.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables in Energy delivered by customer type or class.

Table 4-22: Energy Grouping – Customer Type or Class

Variable		Addressing Basis of Preparation Requirements
DOPED0501-DOPED0505	A	Ergon Energy confirms the category breakdown is consistent with the customer types reported in Table 5.2.1 Customer numbers (refer section 4.2.6.2), with the exception that Other Customer Class Energy Deliveries includes Unmetered energy delivered (which in table 5.1.4 is separately reported for customer numbers). All entry fields are shaded yellow indicating mandatory data fields, and accordingly have been populated for all regulatory years.
	B	Ergon Energy has sourced information from: ▪ Monthly Network Billing (Netbill) files provided by the STC. ▪ Note: these sources were adopted also for Template 2, table 2.2 Revenue Grouping by customer class or type.
	C	Historically, Ergon Energy's Network Tariffs have not been aligned to a specific customer class and therefore it was necessary to apply a mapping table to obtain the disaggregation required (refer to below). Note: this mapping table was also adopted for Template 2, table 2.2 Revenue Grouping by customer class or type.

	BENCHMARING RIN VARIABLES	ERGON NETWORK TARIFF	ERGON TARIFF DESCRIPTION
Table 5.1.4 Energy grouping - customer type or class			Typical Consumption Levels

Variable	Addressing Basis of Preparation Requirements			
	DOPED0501	Residential Customers Energy Deliveries	Volume Small, Night Controlled and Controlled	Energy Consumption below 26MWh p.a. No demand component
	DOPED0502	Non-residential customers not on demand tariffs energy deliveries	Volume Large	Energy Consumption between 26MWhs and 100MWhs No demand component
	DOPED0503	Non-residential low voltage demand tariff customers energy deliveries	Demand High Voltage, Demand Large, Demand Medium and Demand Small	Energy Consumption between 100MWhs and 4,000MWhs. Demand charge based on minimum chargeable demand
	DOPED0504	Non-residential high voltage demand tariff customers energy deliveries	ICC, CAC and EMG	Energy Consumption greater than 4,000MWhs Demand based on Authorised or Capacity component and an Actual Demand component
	DOPED0505	Other Customer Class Energy Deliveries	Unmetered Supply - Minor and Major Streetlights;	Unmetered Supply connections other than Streetlights No demand component Unmetered Supply - Minor and Major Streetlights No demand component
D	Ergon Energy has provided 'Estimated Information' (as per the AER's defined term) in relation to all variables contained in template 5, table 5.1.4 using the above mapping table as this is Ergon Energy's best estimate.			
E	Energy delivered data is a non-financial data set, and accordingly this requirement is not applicable.			

4.2.6.2 Customer Numbers

The AER requires information to be reported on Ergon Energy's distribution customers in its network during a year. In addition to Notice requirements, on 4 February 2014 the AER provided the following clarification in relation to Customer Numbers:

> *The definition (in Chapter 9 of the Instructions and Definitions) and the corresponding explanation in section 6.2.1 of the explanatory statement exclude 'deactivated' NMIs. A 'deactivated' NMI is equivalent to a NMI that is 'extinct'. This is a NMI with a status code of 'X' in accordance with AEMO's MSATS CATS procedure.*

The definition includes (as explained in the explanatory statement) de-energised NMIs (status code 'D'). For the avoidance of doubt, our definition of customer numbers includes NMIs with status codes 'A' (Active) and 'D' (Not energised). Our definition does not include NMIs with status codes 'X' (Extinct) or 'G' (Greenfield site).

Distribution Customer Numbers By Customer Type or Class

Template 5, table 5.2.1 requires Ergon Energy to report Customer Numbers in accordance with the customer type or class categorisations as defined in the Instructions and Definitions at Appendix B of the RIN.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for Distribution Customer numbers by customer type or class. Of note, DOCPN01 *total customer numbers* represents the sum of variables DOPCN0101 to DOPCN0106, and is therefore implicitly addressed in the responses below.

Table 4-23: Distribution Customer Numbers by Customer Type or Class

Variable		Addressing Basis of Preparation Requirements
DOPCN0101-DOPCN0106 DOCPN01	A	All entry fields are shaded yellow indicating mandatory data fields, and accordingly have been populated for all regulatory years. Ergon Energy confirms the category breakdown is consistent with the customer types reported in Table 5.1.4 Energy grouping - customer type or class (refer section above), with the exception that Unmetered customer numbers are reported separate to "Other Customer" class (in table 5.1.4 they are combined as 'other). 'Other Customer Numbers' (DOPCN0106) was utilised only where customers were unable to be allocated to the other customer classes. Ergon Energy notes that DOCPN01 does NOT reconcile to DOPCN02 in Distribution Customer Numbers by Network Location, given DOCPN01 includes isolated, transmission or unknown (unclassified) feeder classes.
	B	Ergon Energy has sourced customer numbers data from the Market Transaction system (NEMLink). Counts are of unique National Metering Identifiers (NMIs) that are identified as having Ergon Energy as their DNSP.
	C	Distribution Customers (except for unmetered customer numbers) represent the average number of active NMIs in the network the relevant regulatory, calculated as the average number of NMIs on the first day of the regulatory year and on the last day of the regulatory year. Of note: ▪ Each NMI has been counted as a separate customer; ▪ Both energized and de-energised NMIs are counted; and ▪ Extinct and Greenfield site NMIS are excluded. Residential data is identified by the NMI Customer Classification Code (CCC), whilst Voltage, Demand & Unmetered splits were identified by the Network Tariff Types. For Unmetered customers, data presents the sum of unmetered connections (excluding public lighting connections) in the network and the energy usage for billing purposes is calculated using an assumed load profile. Specifically, public lighting

Variable		Addressing Basis of Preparation Requirements
		customers were not counted as unmetered customers.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 5, table 5.2.1, with the exception of regulatory years 2005/06-2006/07 all numbers (DOPCN0101-DOPCN0106 and DOPCN01) and 2007/08 Unmetered Customers Numbers (DOPCN0105) which Estimated Information. For 2005/06-2006/07 all numbers (except Unmetered) Customer Number data was estimated based on the trend growth of the subsequent regulatory years. For 2005/06-2007/08 Unmetered Customers Numbers was back cast using a methodology whereby the proportion of Unmetered customers to the total customers as per 2008/09 was assumed for all prior years. Accordingly, where total customer numbers includes estimates, it is itself, an estimate.
	E	Customer numbers data is a non-financial data set, and accordingly this requirement is not applicable.

Distribution Customer Numbers by Network Location

Template 5, table 5.2.2 requires Ergon Energy to report Customer Numbers in accordance with the customer locations on the network, as defined in the Instructions and Definitions at Appendix B of the RIN. The locations are: Urban, Short Rural Long Rural.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for customer numbers by network location. Of note, DOCPN02 *total customer numbers* represents the sum of variables DOPCN0202 to DOPCN0204, and is therefore implicitly addressed in the responses below.

Table 4-24: Distribution Customer Numbers by Network Location

Variable		Addressing Basis of Preparation Requirements
DOPCN0201-DOPCN0204 DOPCN02	A	All entry fields are shaded yellow indicating mandatory data fields, and accordingly have been populated for all regulatory years, with the exception of 'DOOPCN0201' for CBD Network - Ergon Energy does not have any feeders classified as CBD. Ergon Energy notes that DOPCN02 does NOT reconcile to DOPCN01 in Distribution Customer Numbers by Network Location, given DOCPN01 includes isolated, transmission or unknown (unclassified) feeder classes. No category was provided for these customers in DOPCN0201-DOPCN0204.
	B	Ergon Energy has sourced customer numbers data from the Market Transaction system (NEMLink). Counts are of unique NMIs that are identified as having Ergon Energy as their LNSP.
	C	Distribution Customers represents the average number of active NMIs in the network the relevant regulatory, calculated as the average number of NMIs on the first day of the regulatory year and on the last day of the regulatory year. Of note: ▪ Each NMI has been counted as a separate customer;

Variable		Addressing Basis of Preparation Requirements
		▪ Both energized and de-energised NMIs are counted; and ▪ Extinct and Greenfield site NMIS are excluded. In order to disaggregate data by feeder types (Urban, Short Rural and Long Rural), Ergon Energy, a NMI was identified as being attached to a feeder which in turn enabled the identification of the required feeder classes.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 5, table 5.2.2, with the exception of regulatory year 2005/06 where all numbers provided are Estimated Information.
	E	Customer numbers data is a non-financial data set, and accordingly this requirement is not applicable.

4.2.6.3 System Demand

The AER requires Ergon Energy to provide back cast System Demand data where it has calculated historical Weather Adjustment Maximum Demand statistics. Where specified by orange shading, if Ergon Energy does not have historical data, it may be estimated or cells blacked out (not provided) rather than produce unnecessarily burdensome estimates, and where it is illogical to enter '0'.

Annual System Maximum Demand (Zone Substation) (MW)

Specifically, template 5 table 5.3.1 requires Ergon Energy to report coincident and non-coincident Maximum Demand at the Zone Substation level, as raw (or unadjusted) and Weather Adjusted at the 10% and 50% Probability of Exceedence (POE) levels.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to annual system maximum demand (zone substation) MW variables.

Table 4-25: Annual System Maximum Demand (Zone Substation) (MW)

Variable		Addressing Basis of Preparation Requirements
DOPSD0101-DOPSD0106	A	Variables DOPSD0102, DOPSD0103, DOPSD0105 and DOPSD0106 have been populated by Ergon Energy. All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years.
	B	Data has been sourced from Statistical Metering Database (SMDB). Ergon Energy maintains a series of secure, managed databases known as the Statistical Metering Database (SMDB) that contain historic demand and weather (sourced from the Bureau of Meteorology data). For the purpose of data auditing, a full version control of the metered data is maintained within SMDB and the database is regularly backed-up. Access to the environment is secure and provided only to those persons who require access in order to conduct and manage the load forecasting process, and planning studies, with any changes to the datasets tracked and recorded. The database is constantly being fed new demand data from a variety of sources including:

<table>
<tr><th>Variable</th><th></th><th>Addressing Basis of Preparation Requirements</th></tr>
<tr><td></td><td></td><td>

AEMO accredited Meter Data Agents (MDA) for:

All NEM meter data file formatted (MDFF) data for Transmission Connection Points (and hence Ergon Energy System Total Demand) and market customer meter data;
Dedicated type 4 metering on distribution feeders/power transformers;

Type 4 meter data of non-market customer as interrogated by the Ergon Energy accredited MDA;
Supervisory Control and Data Acquisition (SCADA) at the Bulk Supply Points and Zone-Substations (ZSS);
Other sources within Ergon Energy for:

NULEC recloser downloads;
Maximum Demand Indicator (MDI) readings, and
Simulations of maximum demand based on premises consumption records (billing) and network topology when the above sources are unavailable.

</td></tr>
<tr><td></td><td>C</td><td>In order to obtain Weather adjusted variables, Ergon Energy has employed the following methodology for all years:

Constructing a multivariate maximum demand equation for each season of Summer or Winter. Variables in the equation include maximum temperature, minimum temperature and variables for Saturday, Sunday and public holidays.
Daily historical BOM temperatures are passed through each equation and maximum annual demand is obtained. The listing of annual peak demand is made for all set of consistent temperature records from each associated weather station.
50 POE and 10 POE measured from histogram of annual peak demands.

</td></tr>
<tr><td></td><td>D</td><td>Ergon Energy has provided ‘Actual Information’ (as per the AER’s defined term) in relation to all variables contained in template 5, table 5.3.1.</td></tr>
<tr><td></td><td>E</td><td>Data in relation to Maximum Demand is a non-financial data set, and accordingly this requirement is not applicable.</td></tr>
</table>

Annual System Maximum Demand (Transmission Connection Point) (MW)

Template 5, table 5.3.2 requires Ergon Energy to report coincident and non-coincident Maximum Demands at the Zone Substation level, as raw (or unadjusted) and Weather Adjusted at the 10% and 50% POE levels.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to annual system maximum demand (transmission connection point) MW variables.

Table 4-26: Annual System Maximum Demand (Transmission Connection Point) (MW)

Variable		Addressing Basis of Preparation Requirements
DOPSD0107-DOPSD0112	A	The orange cells associated with Variable Codes DOPSD0108, DOPSD0109 and DOPSD0111 and DOPSD0112 have been populated. All other entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years.
	B	Data has been sourced from Statistical Metering Database (SMDB). Refer Table 4-25.
	C	In order to obtain Weather adjusted variables, Ergon Energy has employed a methodology involving: ▪ Constructing a multivariate maximum demand equation for each season of Summer or Winter. Variables in the equation include maximum temperature, minimum temperature and variables for Saturday, Sunday and public holidays. ▪ Daily historical BOM temperatures are passed through each equation and maximum annual demand is obtained. The listing of annual peak demand is made for all set of consistent temperature records from each associated weather station. ▪ Weather station selected by referral to associated Zone Substation weather station. Where a transmission connection point has multiple Zone Substations attached, the most common weather station is selected for the transmission connection point weather correction. ▪ 50 POE and 10 POE measured from histogram of annual peak demands.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 5, table 5.3.2.
	E	Data in relation to Maximum Demand is a non-financial data set, and accordingly this requirement is not applicable.

Annual System Maximum Demand (Zone Substation) (MVA)

Template 5, table 5.3.3 requires Ergon Energy to report coincident and non-coincident Maximum Demands as raw (or unadjusted) and Weather Adjusted at the 10% and 50% POE levels.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to annual system maximum demand (zone substation) MVA variables

Table 4-27: Annual System Maximum Demand (Zone Substation) (MVA)

Variable		Addressing Basis of Preparation Requirements
DOPSD0201-DOPSD0206	A	The orange cells associated with Variable Codes DOPSD0202, DOPSD0203 and DOPSD0205 and DOPSD0206 have been populated. All other entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years.

Variable		Addressing Basis of Preparation Requirements
	B	Data has been sourced from Statistical Metering Database (SMDB). Refer Table 4-25.
	C	Weather adjustment MVA data has obtained by multiplying MVA by the ratio of (MW temperature adjusted value by MW value) for the same regulatory year.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 5, table 5.3.3.
	E	Data in relation to Maximum Demand is a non-financial data set, and accordingly this requirement is not applicable.

Annual System Maximum Demand (Transmission Connection Point) (MVA)

Template 5, table 5.3.4 requires Ergon Energy to report coincident and non-coincident Maximum Demands as raw (or unadjusted) and Weather Adjusted at the 10% and 50% POE levels.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to annual system maximum demand (transmission connection point) MVA variables.

Table 4-28: Annual System Maximum Demand (Transmission Connection Point) (MVA)

Variable		Addressing Basis of Preparation Requirements
DOPSD0207-DOPSD0212	A	The orange cells associated with variable DOPSD0208, DOPSD0209 and DOPSD0211 and DOPSD0212 have been populated. All other entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years.
	B	Data has been sourced from Statistical Metering Database (SMDB). Refer Table 4-25.
	C	Weather adjustment MVA data has obtained by multiplying MVA by the ratio of (MW temperature adjusted value by MW value) for the same regulatory year.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 5, table 5.3.4.
	E	Data in relation to Maximum Demand is a non-financial data set, and accordingly this requirement is not applicable.

Power Factor Conversion between MVA and MW

Template 5, table 5.3.5 requires Ergon Energy to report the power factor to allow for conversion between MVA and MW measures for each voltage. Ergon Energy is required to provide a power factor for each voltage level and for the network as a whole.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to Power Factor Conversion variables.

Table 4-29: Power Factor Conversions (Overall Network)

Variable		Addressing Basis of Preparation Requirements
DOPSD0301	A	DOPSD0301 is shaded yellow indicating a mandatory data field, and has been populated for all regulatory years.
	B	Ergon Energy extracted power factor data from kW and kVA information stored in the Ergon Energy DNSP central data repository (Statistical Metering Database (SMDB)), which extracts this information from metering units across a significant proportion of Zone Substations over half hourly intervals.
	C	DOPSD0301 '*average overall power factor conversion*' is required to represent the total MW divided by the total MVA. The overall network power factor was derived from a summation of kW and kVA at all the transmission network connections points in the Ergon Energy network, with the peak demand power factor calculated from this data set.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 5, table 5.3.5.
	E	Data in relation to Maximum Demand is a non-financial data set, and accordingly this requirement is not applicable.

Table 4-30: Power Factor Conversions (Remaining Voltage Levels)

Variable		Addressing Basis of Preparation Requirements
DOPSD0302-DOPSD0309	A	All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years.
	B	Ergon Energy extracted power factor data from kW and kVA information stored in the SMDB, which extracts this information from metering units across a significant proportion of feeders and averages the data over half hourly intervals
	C	Ergon Energy developed a software system to calculate the average peak power factor (the power factor at peak demand for all of the aforementioned metering points with data stored in the SMDB at the different voltage levels required by the Notice. Basic data cleansing was performed by eliminating all feeders with peak power factors less than 0.4 and greater than 0.99. Estimates were required for the years 2008 to 2012 for the SWER lines (DOPSD0304) as there is a scarcity of good data in the SMDB for those years, given the remote location of SWER and lack of metering resources. There is a higher confidence in the data for years 2006, 2007 and 2013 (however still with a very small sample size), so actual data is provided for those years, with a linear extrapolation performed between the 2007 and 2013 power factors for the intervening years.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 5, table 5.3.5 except for DOPSD0304 which contains estimates for the years 2008 to 2012.

Variable		Addressing Basis of Preparation Requirements
	E	Data in relation to Maximum Demand is a non-financial data set, and accordingly this requirement is not applicable.

Demand Supplied (for Customers Charged on this Basis) (MW)

Template 5, table 5.3.6 is required to be completed, where Ergon Energy charges customers for Maximum Demand supplied. Ergon Energy is required to report Maximum Demand amounts for customers that are charged based upon their Maximum Demand as measured in MW – split between Contracted and Measured.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for Maximum Demand Supplied (MW).

Table 4-31: Demand Supplied (for Customers Charged on this Basis) (MW)

Variable		Addressing Basis of Preparation Requirements
DOPSD0401 **DOPSD0402**	A	All entry fields are shaded yellow indicating mandatory data fields however it is noted in the Notice that population is only required where Ergon Energy charges customers for Maximum Demand supplied. Accordingly, where Ergon Energy has charged customers for maximum demand supplied, cells have been populated across Regulatory Years. In instances where Ergon Energy cannot distinguish between contracted and measured Maximum Demand, demand supplied was allocated to contracted Maximum Demand.
	B	Ergon Energy has sourced data from the Network Billing system (Netbill).
	C	Network Use of System (NUOS) charges classed as Network DUOS Capacity Charge (NDCC) were used to identify the Contracted demand proportions for Individually Calculated Customer (ICC), Connection Asset Customer (CAC) and Embedded Generator (EG) type connections. NUOS charges classed as Network DUOS Actual Demand Charge (NDADC) were used to identify the Measured demand proportions for ICC, CAC and EG type connections. All Standard Asset Customer (SAC) - Large connections are noted to only have an Actual demand charge and therefore were reported under the Contracted Demand split.
	D	Demand Supplied (contracted and measured) (MW) is supplied as Actual Information (defined term), with the exception the following Estimated Information: ▪ 20005/06-2006/07 data which was not obtainable due to a change in Ergon Energy billing systems. ▪ Accordingly, 2005/06-2006/07 data was estimated based on a trend growth of the subsequent years. Trend growth was arrived at using standard functions within excel.

Variable		Addressing Basis of Preparation Requirements
	E	Data in relation to Demand Supplied is a non-financial data set, and accordingly this requirement is not applicable.

Demand Supplied (for Customers Charged on this Basis) (MVA)

Template 5, table 5.3.7 is required to be completed, where Ergon Energy charges customers for demand supplied. Ergon Energy is required to report Maximum Demand amounts for customers that are charged based upon their Maximum Demand as measured in MVA – split between Contracted and Measured.

Table 4-32: Demand Supplied (for Customers Charged on this Basis) (MVA)

Variable		Addressing Basis of Preparation Requirements
DOPSD0403 **DOPSD0404**	A	All entry fields are shaded yellow indicating mandatory data fields however it is noted in the Notice that population is only required where Ergon Energy charges customers for Maximum Demand supplied. This was also confirmed following AER review of Ergon Energy's initial submission of the Benchmarking RIN, in which Ergon Energy had calculated (using a conversion factor) data on an 'MVA measure' basis. Ergon Energy does not currently charge customers on a kVA (MVA) basis. Accordingly, information was not available in regards to MVA measures of Demand Supplied for contracted and Measured demand over the historical Regulatory Years, and "zeroes" were entered.
	B	Not applicable
	C	Not applicable
	D	Not applicable
	E	Not applicable

4.2.7 Physical Assets

The AER requires a quantity measure of the capital service flow used by the DNSP into the production process for economic benchmarking. However, this cannot be directly observed. Only the quantity of the stock of capital can be observed at any point in time. Therefore, it is necessary to use proxy measures of capital service flow.

The AER requires data on the quantities and capacities of physical assets. Capacities are required to be reported in MVA-kms for lines and cables and in MVA for transformers, to be used as a measure of the capital service flow.

4.2.7.1 Network Capacities Variables

Specifically, template 6 table 6.1 requires Ergon Energy to report capacity variables for its whole network. In this context, the network is to include overhead power lines and towers, underground cables and pilot cables that transfer electricity from the regional bulk supply points supplying areas of consumption to individual zone substations, to distribution substations and to customers. Network is also to include distribution feeders and the low voltage distribution system, but exclude the final connection from the mains to the customer and also wires or cables for public lighting, communication, protection or control and for connection to unmetered loads.

Overhead Network Length of Circuit at each Voltage

Template 6 table 6.1.1 requires the Length of Circuit at each voltage to be reported for overhead portion of the network. Of note, on 3 December 2013 the AER provided clarification to NSPs in regard to completion of variables in table 6.1.1:

> *….variables contained within Tables 6.1.1 [and 6.1.3] do not include the length or capacity of service lines. The correct, compliant completion of Tables 6.1.1 and 6.1.3 is to report the circuit length and circuit capacity excluding the circuit length and circuit capacity of service lines.*

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to overhead network circuit lengths, for each voltage level. Of note, DPA01 – 'Total overhead circuit km' represents the sum variables DPA0101 to DPA0108, and is therefore implicitly addressed in the table below.

Table 4-33: Overhead Network Length of Circuit at each Voltage

Variable		Addressing Basis of Preparation Requirements
DPA0101-DPA0110 DPA01	A	All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years. Additional rows have been inserted at DPA0108 "Other overhead voltages" to account for voltages other than those prescribed by the AER. Circuit length has been calculated from the route length (measured in kilometers) of lines in service (the total length of feeders including all spurs), where each Single Wire Earth Return (SWER) line, single-phase line, and three phase line counts as one line. A double circuit line has been counted as two lines. Circuit length does not take into account vertical components such as sag.
	B	Overhead Network length data of circuits at each voltage level was sourced by Ergon Energy from its Smallworld Oracle Replicated (SOREP) Spatial database. This database is replicated from the Smallworld geographic information system (GIS) electrical data store.
	C	Within Smallworld, changes to electrical assets are maintained in secondary records, with the history of the changes maintained in design actions and design transition logs. Based on this data, routines were run to re-create the overhead conductors in separate tables, as they would have been at the end of each regulatory (financial) year. Scripts were run to extract the number and length of conductors for each financial year, broken down by operating voltage. Conductors with operating voltages which didn't align with any prescribed categories were placed in the "Other Overhead Voltages" group. Conductors with an operating voltage of 12.7kV and 19.1kV were placed in the SWER category.

Variable		Addressing Basis of Preparation Requirements
		This methodology assumes that all conductors were maintained using design actions. Historically, this has not always been the case, and this will introduce a level of inaccuracy to the reported figures.
	D	Ergon Energy has provided ‘Actual Information’ (as per the AER’s defined term) in relation to all variables contained in template 6, table 6.1.1.
	E	Physical Assets data is a non-financial data set, and accordingly this requirement is not applicable.

Underground Network Circuit Length at Each Voltage

Template 6 table 6.1.2 requires the Length of Circuit at each voltage to be reported for Underground portion of Ergon Energy’s network.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to Underground network circuit lengths, for each voltage level. Of note, DPA02 – ‘Total underground circuit km’ represents the sum variables DPA0201 to DPA0207, and is therefore implicitly addressed in the table below.

Table 4-34: Underground Network Circuit Length at each Voltage

Variable		Addressing Basis of Preparation Requirements
DPA0201-DPA0208 DPA02	A	All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years. Additional rows have been inserted at DPA0207 “Other underground voltages” to account for all voltages other than those prescribed by the AER. Circuit length has been calculated from the route length (measured in kilometers) of lines in service (the total length of feeders including all spurs), where each single-phase line, and three phase line counts as one line. A double circuit line has been counted as two lines. Circuit length does not take into account vertical components such as sag.
	B	Underground Network length data of circuits at each voltage level was sourced by Ergon Energy from its SOREP Oracle Spatial database. This database is replicated from the Smallworld GIS electrical data store.
	C	Within Smallworld, changes to electrical assets are maintained in secondary records, with the history of the changes maintained in design actions and design transition logs. Based on this data, routines were run to re-create the underground conductors in separate tables, as they would have been at the end of each regulatory (financial) year. Scripts were run to extract the number and length of conductors for each financial year, broken down by operating voltage. Conductors with operating voltages which didn’t align with any prescribed categories

Variable		Addressing Basis of Preparation Requirements
		were placed in the “Other Underground Voltages” group. This methodology assumes that all conductors were maintained using design actions. Historically, this has not always been the case, and this will introduce a level of inaccuracy to the reported figures.
	D	Ergon Energy has provided ‘Actual Information’ (as per the AER’s defined term) in relation to all variables contained in template 6, table 6.1.2.
	E	Physical Assets data is a non-financial data set, and accordingly this requirement is not applicable.

Estimated Overhead Network Weighted Average Capacity by Voltage Class (MVA)

Template 6, table 6.1.3 requires Ergon Energy to provide estimated typical or weighted average capacities for each of the listed overhead voltage classes prescribed by the AER, under normal circumstances taking account of limits imposed by thermal or by voltage drop considerations as relevant. Capacity is to be provided in an MVA measure.

The AER requires this information to calculate an overall MVA x km ‘carrying capacity’ for each overhead voltage class under normal circumstances.

On 4 February 2014, the AER also provided (at Ergon Energy’s request) the following clarification with regards to requirements in respect of reporting requirements for Tables 6.1.3:

> *We are not requesting separate weighted average capacities for summer and winter. We are requesting the weighted average capacity for the whole network in summer if the majority of that network experiences maximum demand in summer. Conversely, we are requesting the weighted average capacity for the whole network in winter if the majority of that network experiences maximum demand in winter. ….*
>
> *That is, we are requesting the weighted average MVA capacity circuit capacity calculated using the capacities (under system normal conditions) at the time of overall system Maximum Demand.*

Further to this, on 3 December 2013, the AER provided the following clarification to NSPs:

> *….variables contained within [Tables 6.1.1 and] 6.1.3 do not include the length or capacity of service lines. The correct, compliant completion of Tables 6.1.1 and 6.1.3 is to report the circuit length and circuit capacity excluding the circuit length and circuit capacity of service lines.*
>
> *A stakeholder has asked whether two sets of lines that run on different sets of poles (or towers) but share the same easement should count as one route or two for the variable DOEF0301. We confirm that in this instance the lines are to be counted separately. The correct, compliant response to the variable DOEF0301 where two sets of lines share the same easement but run on separate sets of poles (or towers) is to count these lines as separate routes when reporting total route line length.*

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables relating to estimated Overhead network weighted average capacities (MVA).

Table 4-35: Estimated Overhead Network Weighted Average Capacity by Voltage Class (MVA)

Variable		Addressing Basis of Preparation Requirements
DPA0301-DPA0310	A	All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years. Where two sets of lines run on different sets of poles (or towers) but share the same easement these are counted as separate routes for the variable DOEF0301. No circuit capacity has been assigned to unknown voltages.
	B	Ergon Energy has sourced data from, and made reference to the following standards or guidelines, in order to complete variables for Estimated Overhead Network Weighted Average Capacity, by Voltage Class (MVA): ▪ SOREP Oracle Spatial database (replicated SmallWorld GIS electrical datastore); ▪ Australian Standards; ▪ IEC Standards; ▪ ESAA D(b)5; and ▪ Ergon Energy Plant Rating Guidelines.
	C	Data in relation to Table 6.1.1 ‘Overhead network length of circuit at each voltage’ was used. A methodology was employed whereby for lines interacting with more than one climate zones, the lowest rating was applied. Summer ratings were calculated.
	D	Ergon Energy has provided ‘Actual Information’ (as per the AER’s defined term) in relation to all variables contained in template 6, table 6.1.3.
	E	Overhead network weighted average capacities reported are a non-financial data set, and accordingly this requirement is not applicable.

Estimated Underground Network Weighted Average Capacity by Voltage Class (MVA)

Template 6, table 6.1.4 requires Ergon Energy to provide estimated typical or weighted average capacities for each of the listed underground voltage classes prescribed by the AER, under normal circumstances taking account of limits imposed by thermal or by voltage drop considerations as relevant. Capacity is to be provided in an MVA measure.

The AER requires this information to calculate an overall MVA x km ‘carrying capacity’ for each voltage class under normal circumstances. Refer also to abovementioned additional guidance received from AER (4 February 2014) in regard to Table 6.1.4.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables in relation to estimated Underground network weighted average capacities (MVA).

Table 4-36: Estimated Underground Network Weighted Average Capacity by Voltage Class (MVA)

Variable		Addressing Basis of Preparation Requirements
DPA0401-DPA0408	A	All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years.

Variable		Addressing Basis of Preparation Requirements
	B	Ergon Energy has sourced data from, and made reference to the following standards or guidelines, in order to complete variables for Estimated Underground Network Weighted Average Capacity, by Voltage Class (MVA) : ▪ SOREP Oracle Spatial database (replicated SmallWorld GIS electrical datastore); ▪ Olex cable manufacturer catalogue calculations; ▪ Australian Standards; ▪ IEC Standards; and ▪ Ergon Energy Plant Rating Guidelines.
	C	Data in relation to Table 6.1.2 'Underground circuit length each voltage' was used. Of note, the following assumptions were applied. ▪ Cables with similar characteristics given the same rating; ▪ Cables ambient air temperature calculated from spatial analysis with Ergon Energy Climate Zones; ▪ Cables ground air temperature calculated from spatial analysis with 9 BOM Weather stations (nearest); ▪ Unknown Voltage & Phase attributes calculated from cable characteristics; ▪ Cables ratings assumed 2 adjacent cables, 900mm depth, Cyclic Rating Factor =1, Solid Bonded & TR=2.0; ▪ Summer & Winter Ratings were calculated.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 6 table 6.1.4.
	E	Underground network weighted average MVA capacity reported is a non-financial data set, and accordingly this requirement is not applicable.

4.2.7.2 Transformer Capacities Variables

The AER requires information pertaining to the capacity of Ergon Energy's installed Distribution and Zone Substation transformers. Information is required in relation to distribution transformer capacity both owned by Ergon Energy, and owned by its high voltage customers. Cold spare capacity (included in total capacity) is also required to be separately reported for both Distribution and Zone Substation transformers.

Distribution Transformer Total Installed Capacity

Specifically, template 6 table 6.2.1 requires Ergon Energy to report total installed Distribution Transformer capacity both owned by Ergon Energy and by high voltage customers. Cold spare capacity included in Ergon Energy's total capacity is to also be separately identified.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to Distribution transformer total installed capacity.

Table 4-37: Distribution Transformer Total Installed Capacity

Variable		Addressing Basis of Preparation Requirements
DPA0501-DPA0503	A	All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years. Distribution transformer capacity owned by Ergon Energy (DPA0501) - the reported data is the nameplate continuous rating including forced cooling. Where the transformer capacity owned by the customers connected at high voltage (DPA0502) was not available, Ergon Energy reported the summation of individual Maximum Demands of high voltage customers whenever they occur (i.e. the summation of single annual Maximum Demand for each customer) as a proxy for delivery capacity within the high voltage customers. DPA0503 Cold Spare Capacity represents the total capacity of spare transformers owned by Ergon energy but not currently in use. Cold Spare Capacity is included in Distribution transformer capacity owned by Ergon Energy (DPA0501).
	B	The source data for Distribution transformer capacity owned by High Voltage was obtained from the DCOS and billed summary file (Netbill & FACOM). The total capacity of installed distribution transformers was sourced from a Current State Assessment database which each year stores the amount of distribution transformer capacity connected to each distribution feeder. The installed distribution transformer capacity is stored in Ergon Energy's corporate database. The source of the distribution transformer cold capacity is detailed in the table below.
	C	For Distribution transformer capacity owned by, ICC & CAC customers were taken from the annual DCOS file after removing those metered at low voltage (415 line etc). Following, the maximum of actual charged maximum demand for each year or authorised demand was taken for each connection point. (Note: a connection point must have capacity of at least the authorised demand). The DCOS totals were then added to the of SACHV connections. DCOS numbers were used for SAC HV as no reliable, consistent, like for like, data for SAC High voltage connections is available over the required period. However, given that SACHV is less than 2% of totals, this was considered an acceptable estimation. The data is obtained from monthly billing files received from Service Transaction Centre using Netbill, and other files produced for Pricing purposes. A conversion factor was used to present the figures in MVA. The distribution transformer cold capacity was added to the installed capacity values. Refer to Table 4-38 below, for source and methodology employed for Cold Spare Capacity variables.
	D	[DPA0501] Distribution transformer capacity owned by Ergon Energy is 'Estimated Information (as per the AER's defined term) for years 2005/06 to 2012/13. Ergon Energy is currently unable to confirm the accuracy of historical system data therefore a trend-line approach has been applied and Estimates of distribution transformer capacity have been provided for years (2005/06 – 2012/13) based on the

Variable		Addressing Basis of Preparation Requirements
		available historical data. Ergon Energy is unable to provide Actual Information for Distribution transformer capacity owned by High Voltage Customers therefore estimated information has been presented in accordance with the Instruction at Table 6.2 Transformer Capacities Variables.
	E	Capacity of installed distribution transformers is a non-financial data set, and accordingly this requirement is not applicable.

The following comments relate to cold spare capacity reporting as relevant to both variables DPA0503 (distribution transformer cold spare capacity) and DPA0605 (zone substation transformer cold spare capacity).

Table 4-38: Cold Spare Capacity (Distribution Transformer and Zone Substation)

Variable		Addressing Basis of Preparation Requirements
DPA0503 **DPA0605**	A	All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years. Cold Spare Capacity represents the total capacity of spare transformers owned by Ergon energy but not currently in use. Cold spare capacity is included in the total Distribution transformer capacity owned by Ergon Energy (DPA0501), and total zone substation transformer capacity (DPA0604).
	B	Relevant to DPA0503 and DPA0605, cold spare capacity data was sourced from the Ellipse Production table files using a Structured Query Language (SQL) database query script. This data was taken from transaction records located in the Mincom Ellipse MSF900 table.
	C	In order to obtain the Cold Capacity values required for this report the Stock On Hand (SOH) value for each identified stock code was required at the end of each regulatory (financial) year. As SOH values are a snapshot in time and historical values could not be reported on at any given time, transactional records needed to be interrogated. With every stock transaction created in Ellipse there is a transaction record created in the MSF900 table which includes a value for the SOH after the transaction quantity has been processed. In order to obtain each stock code's SOH value for each regulatory year a SQL script was written to return the last transaction for each stock code in the regulatory year. To calculate the Cold Capacity value in MVA stock on hand value for each regulatory year was multiplied by the Capacity of the item which could be obtained from the Stock Code's description. It can be noted for variable DPA0605 that there is a distinct spike in the value of Cold Spare Capacity for Zone Substations. This spike is due to a change in inventory practice to include a greater number Power Transformers into Ergon Energy's Inventory Catalogue than previous years. Prior to this there were minimal Power Transformers

Variable		Addressing Basis of Preparation Requirements
		kept in stores.
	D	Ergon Energy has provided 'Estimated Information' (as per the AER's defined term) in relation to Cold Spare Capacity contained in template 6 table 6.2.1 and 6.2.2 for 2005/06 year only. Due to change of ERP system in September 2006, historical data prior to this date cannot be obtained. Some stock codes did not have any transactions during a financial year period therefore an assumption had to be made based on the previous years' stock on hand values. For those stock codes where there were no transactions yet there were transaction is a previous year, it was assumed that the SOH value would be the same as the previous financial year as there had been no stock movements. For those stock codes where there were no transactions in the financial year and none in a previous financial year it was assumed that stock had yet to be included in the inventory catalogue.
	E	Cold spare capacity is a non-financial data set, and accordingly this requirement is not applicable.

Zone substation Transformer Capacity

Template 6, table 6.2.2 requires Ergon Energy to report transformer capacity for intermediate level transformation capacity in either one or two steps. For example, high voltages such as 132 kV, 66 kV or 33kV at the Zone Substation level to the distribution level of 22 kV, 11 kV or 6kV.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to Zone Substation transformer capacity variables.

Table 4-39: Zone Substation Transformer Capacity

Variable		Addressing Basis of Preparation Requirements
DPA0601-DPA0605	A	All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years. Measures are the summation of normal assigned continuous capacity/rating (with forced cooling or other capacity improving factors included). They include both energised transformers and cold spare capacity. The assigned rating must be (if available) the rating determined from results of temperature rise calculations from testing, else the nameplate rating is reported. For zone substations where the thermal capacity of exit feeders is a constraint, thermal capacity of exit feeders is reported instead of transformer capacity. Cold Spare Capacity represents the total capacity of spare transformers owned by Ergon energy but not currently in use. Cold spare capacity is included in the total zone substation transformer capacity (DPA0604).

Variable		Addressing Basis of Preparation Requirements
	B	2012/13 totals are based on current corporate data extracted as a snapshot of the system at the end of the 2012/13 regulatory year. Historical values for 2007/08 to 2011/12 are based on snapshot data used to prepare the annual Network Management Plan (NMP) reports (reporting which preceded the DAPR). This data typically was a much larger set of asset data and the zone substation transformer data was extracted and summated to obtain the required totals. Due to variations in the data purpose and timing relative to the RIN data, this data was used to determine an annual variation that was then applied to the 2012/13 (current) totals to determine each set of annual values.
	C	Transformer asset data was extracted from the corporate database, or stored historical extracts of corporate data, categorised according to Table 6.2.2, and summated to obtain totals. Refer to Table 4-38 above, for source and methodology employed for Cold Spare Capacity variables.
	D	Information for variables contained in template 6 table 6.2.2 pertaining to 2007/08-20012/13 provided by Ergon Energy is considered 'Actual Information'. However, Ergon Energy has provided 'Estimated Information' (as per the AER's defined term) for regulatory years 2005/06- 2006/07. Back-cast data for 2005/06- 2006/07 was not able to be obtained as the snapshot data for these years was not stored. Accordingly, data has been estimated based on a linear extrapolation of the 2007/08-20012/13 data.
	E	Capacity of zone substation transformers is a non-financial data set, and accordingly this requirement is not applicable.

4.2.7.3 Public lighting

The AER requires Ergon Energy to report the number of public lighting luminaires and public lighting poles in its network. For both variables, Ergon Energy is required to report numbers that include both assets owned by Ergon Energy and assets operated and maintained, but not owned by Ergon Energy. Only poles that are used exclusively for public lighting are to be included.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for Public Lighting.

Table 4-40: Public Lighting

Variable		Addressing Basis of Preparation Requirements
DPA0701-DPA0702	A	All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years. Only poles that are used exclusively for public lighting are to be included.

Variable		Addressing Basis of Preparation Requirements
	B	Public Lighting data has been sourced from the Corporate GIS software, SmallWorld.
	C	A methodology was employed whereby queries were developed to identify Public Lighting assets that were established in the database at the end of each regulatory year (financial year). It is assumed that the GIS data is an accurate record of actual assets.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template in Table 6.3 (Public Lighting).
	E	Public lighting data reported is a non-financial data set, and accordingly this requirement is not applicable.

4.2.8 Quality of Services

The AER requires data on service quality for economic benchmarking, particularly because increases in measured efficiency may otherwise be achieved at the expense of service quality in either the short-term or the longer term. Accordingly, the AER are collecting data in relation to the Reliability of Ergon Energy's network (both inclusive and exclusive of Major Event Days (MEDs)), estimates of Energy Not Supplied, as well as System Losses and Capacity Utilisation.

The AER notes Whole of Network SAIDI and SAIFI are to be the system wide SAIDI and SAIFI, and that they don't require information by individual feeder categories within Ergon Energy's network.

4.2.8.1 Reliability

Specifically, in template 7 table 7.1 Ergon Energy is required to report reliability data in relation to the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) for unplanned outages on a Whole of Network basis. Data is required to be reported in accordance with the definitions provided in the AER's *Service Target Performance Incentive Scheme* (STPIS)[3] unless otherwise specified. Performance is required to be reported both inclusive and exclusive of excluded outages as per STPIS, and also then inclusive or exclusive of Major Event Days (MEDs) allowable under the Scheme.

Reliability - Inclusive of Major Event Days (MED)

Template 7 Table 7.1.1 requires Ergon Energy to report System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) in accordance with the definitions provided in Chapter 9 of the RIN Information and Definitions.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to Reliability statistics (inclusive of MEDs).

[3] AER, *Electricity distribution network service providers Service target performance incentive scheme*, November 2009

Table 4-41: Reliability Performance (Inclusive of MEDs)

Variable		Addressing Basis of Preparation Requirements
DQS0101-DQS0104	A	All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years. Data is reported in accordance with the definitions provided in the AER's *STPIS* unless otherwise noted. Data represents Actual performance only in relation to unplanned interruptions, as defined in the AER's STPIS scheme. In the absence of specification, Whole of Network statistics were assumed to encompass the Summation of Urban, Short Rural & Long Rural (Customer Minutes, Customer Interruptions and Customer Numbers). The MED threshold calculated for the 2012/13 Regulatory Year in accordance with the requirements in the STPIS has been applied as the MED threshold for all Regulatory Years for the purpose of identifying the Major event days in all regulatory years.
	B	Ergon Energy has sourced data from its internal outage management and asset management systems.
	C	Refer to Table 4-42 below for methodologies specific to each variable. The following comments are made across all variables. The regulatory (financial) year 2012/13 Major Event Day Threshold (tMed 8.52) was calculated utilising 5 years of Daily SAIDI data using the required STPIS methodology. In this regard, for distribution customer numbers utilised, Ergon Energy notes that: ▪ Monthly number of distribution customers was used as the denominator for the calculation of the reliability Daily SAIDI data for financial years 2007/08, 2008/09, 2009/10 and 2010/11. ▪ Average number of customers (the number of distribution customers is calculated as the average of the number of customers at the beginning of the reporting period and the number of customers at the end of the reporting period) was used as the denominator for the calculation of Daily SAIDI data for financial year 2011/12 as per the formula outlined in Appendix A of the AER's STPIS scheme. ▪ That is to say, while undergoing the 2010/11 Audit of Ergon Energy's Annual Performance RIN, a difference was recognised and Ergon Energy has since implemented the required customer number denominator change for years following 2011/12. Only Completed Unplanned Sustained Interruptions (Interruptions greater that one minute) are included. Public Safety Isolations exclusions were not assessed by Ergon Energy and therefore not applied, prior to the financial year 2010/11. Prior to the year 2010/11, outages relating to interruptions resulting from to service fuse and beyond faults (SF&B) was not routinely cleansed by Ergon Energy, which may result in an overstatement of SF&B faults applied in years 2005/06-2009/10.

Variable		Addressing Basis of Preparation Requirements
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all Reliability statistics.
	E	Reliability information reported is a non-financial data set, and accordingly this requirement is not applicable.

The following comments are made in relation to specific Reliability variables, provided in template 7 table 7.1.1 (Reliability performance inclusive of MEDs). Comments detail the specific scripting utilised to extract data used by Ergon Energy in providing Actual Information.

Table 4-42: Reliability Performance (Inclusive of MEDs) – Specific Variable Responses

Variable	Definition
Whole of network unplanned SAIDI (DQS0101)	Completed Sustained Unplanned Interruptions Feeder Categories: Whole of Network (Summation of Urban, Short Rural & Long Rural) Financial Years 2005/06 to 2012/13 inclusive (Between 1 July and 30 June) SAIDI calculation - Customer Minutes DIVDED BY Average Number of Customers INCLUDE: ▪ Normal ▪ Service Fuse or Beyond ▪ STPIS MED day Exclusions ▪ Generation (Exemption clause: 3.3 (a) (2)) ▪ Shared Transmission (Exemption clause: 3.3 (a) (5)) ▪ Public Safety Isolation (Exemption clause: 3.3 (a) (7)) Exclusions
Whole of network unplanned SAIDI - excluding excluded outages (DQS0102)	Completed Sustained Unplanned Interruptions Feeder Categories: Whole of Network (Summation of Urban, Short Rural & Long Rural) Financial Years 2005/06 to 2012/13 inclusive (between 1 July and 30 June) SAIDI calculation - Customer Minutes DIVDED BY Average Number of Customers INCLUDE: ▪ Normal ▪ Service Fuse or Beyond ▪ STPIS MED day Exclusions EXCLUDE: ▪ Generation (Exemption clause: 3.3 (a) (2)) ▪ Shared Transmission (Exemption clause: 3.3 (a) (5)) ▪ Public Safety Isolation (Exemption clause: 3.3 (a) (7)).

Variable	Definition
Whole of network unplanned SAIFI (DQS0103)	Completed Sustained Unplanned Interruptions Feeder Categories: Whole of Network (Summation of Urban, Short Rural & Long Rural) Financial Years 2005/06 to 2012/13 inclusive (Between 1 July and 30 June) SAIFI calculation - Customers Interrupted DIVDED BY Average Number of Customers INCLUDE: ▪ Normal ▪ Service Fuse or Beyond ▪ STPIS MED day Exclusions ▪ Generation (Exemption clause: 3.3 (a) (2)) ▪ Shared Transmission (Exemption clause: 3.3 (a) (5)) ▪ Public Safety Isolation (Exemption clause: 3.3 (a) (7)) Exclusions
Whole of network unplanned SAIFI - excluding excluded outages (DQS0104)	Completed Sustained Unplanned Interruptions Feeder Categories: Whole of Network (Summation of Urban, Short Rural & Long Rural) Financial Years 2005/06 to 2012/13 inclusive (between 1 July and 30 June) SAIFI calculation - Customers Interrupted DIVDED BY Average Number of Customers INCLUDE: ▪ Normal ▪ Service Fuse or Beyond ▪ STPIS MED day Exclusions EXCLUDE: ▪ Generation (Exemption clause: 3.3 (a) (2)) ▪ Shared Transmission (Exemption clause: 3.3 (a) (5)) ▪ Public Safety Isolation (Exemption clause: 3.3 (a) (7)).

Reliability - Exclusive of MEDs

Table 7.1.2 requires Ergon Energy to report SAIDI and SAIFI in accordance with the definitions provided in Chapter 9 of the information and definitions document in Appendix B to the Notice.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to Reliability statistics (exclusive of MEDs).

Table 4-43: Reliability Performance (Exclusive of MEDs)

<table>
<tr><th>Variable</th><th></th><th>Addressing Basis of Preparation Requirements</th></tr>
<tr><td rowspan="3">DQS0105-
DQS0108</td><td>A</td><td>All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years.

Data is reported in accordance with the definitions provided in the AER’s STPIS unless otherwise noted.

Data represents actual performance only in relation to unplanned interruptions, as defined in the AER’s STPIS scheme.

In the absence of specification, Whole of Network statistics were assumed to encompass the Summation of Urban, Short Rural & Long Rural (Customer Minutes, Customer Interruptions and Customer Numbers).

The MED threshold calculated for the 2012/13 Regulatory Year in accordance with the requirements in the STPIS has been applied as the MED threshold for all Regulatory Years for the purpose of identifying the Major event days in all regulatory years.</td></tr>
<tr><td>B</td><td>Ergon Energy has sourced data from its internal outage management (FeederStat) and asset management systems.</td></tr>
<tr><td>C</td><td>Refer to Table 4-44 below for methodologies specific to each variable. The following comments are made across all variables.

The regulatory (financial) year 2012/13 Major Event Day Threshold (tMed 8.52) was calculated utilising 5 years of Daily SAIDI data using the required STPIS methodology.

In this regard, for distribution customer numbers utilised, Ergon Energy notes that
Monthly number of distribution customers was used as the denominator for the calculation of the reliability Daily SAIDI figures for financial years 2007/08, 2008/09, 2009/10 and 2010/11.
Average number of customers (the number of distribution customers is calculated as the average of the number of customers at the beginning of the reporting period and the number of customers at the end of the reporting period) was used as the denominator for the calculation of the reliability Daily SAIDI figures for financial year 2011/12 as per the formula outlined in Appendix A of the AER's STPIS scheme.
That is to say, while undergoing the 2010/11 Audit of Ergon Energy’s annual performance RIN, a difference was recognised and Ergon Energy has since implemented the required customer number denominator change for years following 2011/12.
Only Completed Unplanned Sustained (Interruptions greater that one minute) Interruptions are included.

Public Safety Isolations exclusions were not assessed by Ergon Energy and therefore not applied, prior to the financial year 2010/11.

Prior to the year 2010/11, outages relating to interruptions resulting from to service fuse and beyond faults (SF&B) was not routinely cleansed by Ergon Energy, which may result in an overstatement of SF&B faults applied in years 2005/06-2009/10.

For financial years 2010/11 and 2011/12 Ergon Energy applied an outage management</td></tr>
</table>

Variable		Addressing Basis of Preparation Requirements
		practice that involved the creation of a number of child outage events within the outage management system to capture small pockets of off supply customers at a point in time when the distribution network was reinstated following a significant outage events. ▪ "Parent Outages" where created to record Outages affecting Feeders on a Major Event Day. The Parent Outage caused a loss of supply to a group of customers that had initially occurred on a Major Event Day. ▪ When some assets were fixed the Parent Outage was closed and '1st' and '2nd' child outages were created and used to continue the outage data capture for the Customers that still had a loss of supply from the Initial Parent Outage. ▪ This is not a normal practice at Ergon Energy but this was exercised to handle the outstanding volume of outages occurred during the MED Days in 2010/11 and 2011/12. ▪ A number of these significant outage events occurred on identified MEDs. As a result the data provided presents a number of smaller outage events identified as MED exempt that do not have a commencement date aligned to a nominated MED. ▪ These outages have been excluded from the normalised SAIDI and SAIFI reports. ▪ The linkage between the original parent outage and each individual child outage was established through a rigorous analysis and review process to ensure accuracy and integrity of the reported performance data. The identified child outage events are: 729422, 729425, 730973, 732660, 732746, 721745, 721914, 721925, 721973, 722033, 722034, 722036, 730277, 722793, 723595, 725259, 724669, 729305, 826385, 829204, 826000, 826276, 826317, 825391, 825525, 825563, 825950, 826233, 826394, 827676, 825815, 825824, 825826 and 825892. ▪ Ergon Energy suspended this practice prior to the commencement of the 2012/13 reporting year.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all Reliability statistics.
	E	Reliability information reported is a non-financial data set, and accordingly this requirement is not applicable.

The following comments are made in relation to specific Reliability variables, provided in template 7 table 7.1.2 (Reliability performance exclusive of MEDs). Comments detail the specific scripting utilised to extract data used by Ergon Energy in providing Actual Information.

Table 4-44: Reliability Performance (Exclusive of MEDs) – Specific Variable Responses

Variable	Definition
Whole of network unplanned SAIDI (DQS0105)	Completed Sustained Unplanned Outages. Feeder Categories: Whole of Network (Summation of Urban, Short Rural & Long Rural).

Variable	Definition
	Financial Years 2005/06 to 2012/13 inclusive (Between 1 July and 30 June) SAIDI calculation - Customer Minutes DIVDED BY Average Number of Customers EXCLUDE: ▪ STPIS MED day Exclusions INCLUDE: ▪ Normal ▪ Service Fuse or Beyond ▪ Generation (Exemption clause: 3.3 (a) (2)) ▪ Shared Transmission (Exemption clause: 3.3 (a) (5)) ▪ Public Safety Isolation (Exemption clause: 3.3 (a) (7)).
Whole of network unplanned SAIDI - excluding excluded outages (DQS0106)	Completed Sustained Unplanned Outages. Feeder Categories: Whole of Network (Summation of Urban, Short Rural & Long Rural). Financial Years 2005/06 to 2012/13 inclusive (Between 1 July and 30 June). SAIDI calculation - Customer Minutes DIVDED BY Average Number of Customers INCLUDE: ▪ Normal ▪ Service Fuse or Beyond EXCLUDE: ▪ STPIS MED day Exclusions ▪ Public Safety Isolation (Exemption clause: 3.3 (a) (7)). ▪ Generation (Exemption clause: 3.3 (a) (2)) ▪ Shared Transmission (Exemption clause: 3.3 (a) (5))
Whole of network unplanned SAIFI (DQS0107)	Completed Sustained Unplanned Outages. Feeder Categories: Whole of Network (Summation of Urban, Short Rural & Long Rural). Financial Years 2005/06 to 2012/13 inclusive (Between 1 July and 30 June). SAIFI calculation - Customers Interrupted DIVDED BY Average Number of Customers EXCLUDE: ▪ STPIS MED day Exclusions INCLUDE: ▪ Normal ▪ Service Fuse or Beyond ▪ Generation (Exemption clause: 3.3 (a) (2))

Variable	Definition
	▪ Shared Transmission (Exemption clause: 3.3 (a) (5)) ▪ Public Safety Isolation (Exemption clause: 3.3 (a) (7)).
Whole of network unplanned SAIFI - excluding excluded outages (DQS0108)	Completed Sustained Unplanned Outages. Feeder Categories: Whole of Network (Summation of Urban, Short Rural & Long Rural) Financial Years 2005/06 to 2012/13 inclusive (Between 1 July and 30 June) SAIFI calculation - Customers Interrupted DIVDED BY Average Number of Customers INCLUDE: ▪ Normal ▪ Service Fuse or Beyond EXCLUDE: ▪ STPIS MED day Exclusions ▪ Public Safety Isolation (Exemption clause: 3.3 (a) (7)). ▪ Generation (Exemption clause: 3.3 (a) (2)) ▪ Shared Transmission (Exemption clause: 3.3 (a) (5))

4.2.8.2 Energy Not Supplied

Template 7 able 7.2 requires Ergon Energy to estimate the raw (not normalized) energy not supplied due to unplanned customer interruptions based on average customer demand (multiplied by the number of customers interrupted and the duration of the interruption).

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to Energy Not Supplied. Of note, Total Energy not Supplied (variable DQS02) represents the total of Planned and Unplanned Energy Not Supplied respectively, and is therefore implicitly addressed in the responses below.

Table 4-45: Energy Not Supplied

Variable		Addressing Basis of Preparation Requirements
DQS0201 **DQS0202** **DQS02**	A	All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years. Although not specified, Planned and Unplanned outage data has been utilised on a Whole of Network basis (Urban, Short Rural and Long Rural). Ergon Energy confirms that energy not supplied has been reported exclusive of the effect of Excluded Outages defined in Appendix B, Instructions and Definitions.
	B	Ergon Energy utilised a combination of customer outage data (refer reliability reporting above – section 4.2.8.1, for data sources) and Netbill billing customer consumption data.

Variable		Addressing Basis of Preparation Requirements
		Network Reliability provided Unplanned and Planned Outage data by Feeder (No exclusions removed,) for Feeder Categories: Urban, Short Rural & Long Rural is noted to INCLUDE: ▪ Normal ▪ Service Fuse or Beyond ▪ STPIS MED day Exclusions EXCLUDE ▪ Public Safety Isolation (Exemption clause: 3.3 (a) (7)) ▪ Generation (Exemption clause: 3.3 (a) (2)) ▪ Shared Transmission (Exemption clause: 3.3 (a) (5)).
	C	Ergon Energy has estimated the raw (not normalised) energy not supplied due to unplanned customer interruptions based on average customer demand (multiplied by the number of customers interrupted and the duration of the interruption). Customer minutes off supply has been calculated by multiplying the duration a feeder is without supply, by the number of customers on the feeder at the time. Customer minutes off supply are then multiplied by the average consumption per affected feeder, to determine an estimate of Energy Not Supplied. This calculation was performed for both Planned and Unplanned interruptions, with Total Energy Not supplied being the sum of DQS0201 and DQS0202 across the regulatory years.
	D	By definition, Ergon Energy has provided 'Estimated Information' in relation to all variables contained in template 7 table 7.2. Historical feeder connectivity is not captured by Ergon Energy, and therefore current connectivity is assumed. Consumption is identified for all feeders and was multiplied by the customer minutes. Where there is no current connectivity an average consumption across all feeders was used.
	E	Energy Not Supplied is a non-financial data set, and accordingly this requirement is not applicable.

4.2.8.3 System Losses

The AER requires Ergon Energy to report system losses, being the proportion of energy lost in distribution of electricity from the transmission network to Ergon Energy customers. The AER provides equation 2 for the purpose of calculating distribution losses.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments relative to template 7 table 7.3 – System Losses.

Table 4-46: System Losses

Variable		Addressing Basis of Preparation Requirements
DQS03	A	All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years. System losses are calculated in accordance with Equation 2 in the Instructions and Definitions at Appendix B to the Notice.
	B	In order to calculate System Losses, data has been sourced from corporate sources as provided in Tables 5.1.1, 5.1.2 and 5.1.3 of the Notice (refer section 4.2.6.1 on Energy Delivery).
	C	All data provided in relation to System Losses is Actual information which is calculated using the following formula: [Energy Received (Table 5.1.2 & 5.1.3) – Energy Delivery (Table 5.1.1)] *divide* Energy Received (Table 5.1.2 & 5.1.3).
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to variable DQS03 contained in template 7, table 7.3.
	E	System Losses reported are a non-financial data set, and accordingly this requirement is not applicable.

4.2.8.4 Capacity Utilisation

The AER requires information in relation to Capacity utilisation, as a measure of the capacity of zone substation transformers that is utilised each year.

Specifically, template 7 table 7.4 requires Ergon Energy to report the sum of non-coincident Maximum Demand at the zone substation level divided by summation of zone substation thermal capacity.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to capacity utilisation.

Table 4-47: Capacity Utilisation

Variable		Addressing Basis of Preparation Requirements
DQS04	A	All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years. For the purpose of this measure, capacities used are the summation of normal assigned continuous capacity/rating (with forced cooling or other capacity improving factors included). The assigned rating must be (if available) the rating determined from results of temperature rise calculations from testing, else the nameplate rating is reported. For zone substations where the thermal capacity of exit feeders is a constraint, thermal capacity of exit feeders is used instead of transformer capacity.
	B	Ergon Energy has sourced data in order to report capacity utilisation from the same

Variable		Addressing Basis of Preparation Requirements
		sources as those reported for DOPSD0201 and DPA0604.
	C	This data was determined by dividing the Non–coincident Summated Raw System Annual Maximum Demand provided as per DOPSD0201 by the Total zone substation transformer capacity as per DPA0604, not including the Cold Spare Capacity. This division was performed for each year required.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 7 table 7.4.
	E	Capacity utilisation data is a non-financial data set, and accordingly this requirement is not applicable.

4.2.9 Operating Environment

The AER requires information on operating environment factors to account for exogenous circumstances that may cause differences in productivity across networks. These include variables relating to Density, Terrains and Weather Stations affecting Ergon Energy's network.

4.2.9.1 Density Factors

Specifically for Template 8 Table 8.1 the AER requires Ergon Energy to provide information in relation to density factors affecting its operating environment. Data is required in relation to Customer Density, Energy Density and Demand Density of Ergon Energy's network (all defined terms in Appendix B, Instructions and Definitions).

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to Density factors variables.

Table 4-48: Density Factors

Variable		Addressing Basis of Preparation Requirements
DOEF0101-DOEF0103	A	All entry fields which are shaded yellow indicating mandatory data fields have been populated for all regulatory years.
	B	Refer to responses provided in relation to the source for each numerator/denominator input as noted below.
	C	Values were obtained by calculation as required in Instructions and Definitions for variables: ▪ Customer Density (DOEF0101) = Total Number of Customers (DOPCN01) / Route Line Length of the Network (DOEF0301) ▪ Energy Density (DOEF0102) = Total MWh (DOPED01)/ Total number of customers of the network (DOPCN01) ▪ Demand Density (DOEF0103) = kVA non-coincident Maximum Demand (Zone

Variable		Addressing Basis of Preparation Requirements
		Substation) (DOPSD0101)/ Total number of Customers of the Network (DOPCN01) Further information on the methodology employed to determine each numerator or denominator input is available in the relevant sections (see Table 4-18: Energy Delivery, Table 4-23: Distribution Customer Numbers by Customer Type or Class and Table 4-25: Annual System Maximum Demand (Zone Substation) (MW) in this document).
	D	Ergon Energy has provided a combination of 'Actual Information' and 'Estimated Information' (as per the AER's defined terms) in relation to all variables contained in template 8 table 8.1. ▪ DOEF0101 Customer density - the route line length are based on estimations for all years except the current year which is an actual. ▪ DOEF0102 Energy density – 2008/10 to 2012/13 are based on actual customer numbers. Earlier years are based on customer number and energy delivery estimates. ▪ DOEF0103 Demand density - 2008/10 to 2012/13 are based on actual customer numbers. Earlier years are based on customer number and energy delivery estimates
	E	Density factor data is non-financial data, and accordingly this requirement is not applicable.

4.2.9.2 Terrain Factors

In Table 8.2, the AER requires information in relation to terrain factors affecting Ergon Energy's network operating environment. Specifically, the AER seeks to understand the Rural and Tropical proportions of the network, splits of vegetation maintenance spans by feeder category, average maintenance span cycles for those feeder categories, and number of trees and defects per span. The AER are also seeking information pertaining to the kilometers of standard vehicle accessible network and spans in bushfire risk.

The AER notes that for certain variables (DOEF0202-204 and DOEF0208-0214), where Ergon Energy has Actual Information, it is required to report all years of available data. However, where Actual Information is not available, Estimate Information is at least required for the most recent Regulatory Year.

For Average Vegetation maintenance Span Cycles (DOEF0206-DOEF0207) information (Actual or Estimate) is required for the full five regulatory years requested.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following general comments in relation to Terrain Factors variables.

Table 4-49: Terrain Factors

Variable		Addressing Basis of Preparation Requirements
DOEF0201-DOEF0214	A	DOEF0201 (rural proportion) and DOEF0205 (total spans) are shaded yellow indicating they are mandatory data fields, and accordingly have been populated for all regulatory years. Similarly, vegetation maintenance span cycles variables (DOEF0206-DOEF0207) have

Variable		Addressing Basis of Preparation Requirements
		been provided as Actual Information for the full five regulatory years requested. Orange cells associated with variable DOEF0202-0204, DOEF0208-0209 have not been populated for the full five regulatory years. Actual Information is not available, therefore Estimate Information has been provided only for the most recent Regulatory Year (2012/13) (refer below). Estimates have been provided for DOEF0212-214 for years prior to 2012/13. Figures assume that network configuration, tropical proportion (DOEF0212), road reserve configuration (DOEF0213) and Bushfire risk areas (DOEF0214) have not changed prior to 2013. Figures used are copied from Actual Information submitted for 2013 year.
	B	Refer responses in Table 4-50, for more information on sources of data.
	C	Refer responses in Table 4-50, for more information on methodologies used.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 8 table 8.2 for Terrain Factors, except where information was not available (DOEF0210-DOEF0214) or was estimated (DOEF0201) prior to 2013. Refer specific responses in Table 4-50 as to the basis of preparation of Estimated Information including assumptions and methodologies employed by Ergon Energy.
	E	Data reported in relation to Terrain Factors is non-financial and therefore this requirement is not applicable.

The following comments are made in relation to specific Terrain Factors variables, provided in template 8 table 8.2. These include comments in relation to the source, and methodologies and assumptions used by Ergon Energy in providing Actual or Estimated Information (as relevant).

Table 4-50: Terrain Factors – Specific Variable Responses

Variable	Addressing Basis of Preparation Requirements
Rural proportion (DOEF0201)	Data in relation to the Rural Proportion (rural short and rural long) of Ergon Energy's network (kms) has been sourced from Smallworld. Of note, Ergon Energy's rural vegetation zones – and therefore the rural vegetation management program costs – include some isolated systems and sub-transmission networks which has been excluded from the rural proportion. Information provided is Actual for the years from 2010/11 to 2012/13 reporting year and Estimated from 2008/09 to 2009/10. Historical feeder classifications are not available to calculate the rural proportion – there is an assumption that the proportion of rural network to urban network has not significantly changed from 2008/09 to 2010/11. With regards to the rural proportion variable DOEF0201, Ergon Energy notes the AER guidance provided on 7 February 2014, which clarified the classification of sub-transmission and low voltage lines into short or long rural (since feeder classifications are only applied to high voltage lines):

Variable	Addressing Basis of Preparation Requirements
	The intention of this variable is to measure the rural proportion of a DNSP's network and our definition for a rural customer is a customer with dependent feeder classifications. For consistency the correct compliant response to DOEF0201 is to report the route line length of feeders classified as either short rural or long rural divided by the total route feeder line length (this is the total feeder route line length for all CBD, urban, short rural and long rural feeders). *We note the unit of measurement for the rural proportion variable in the template is expressed in km rather than as a percentage. The correct unit for this variable is a percentage rather than the actual rural line lengths in km.* Accordingly, data has been prepared as per the formula suggested, and is expressed as a percentage (%) (rather than kms).
Urban and CBD and Rural vegetation maintenance spans (DOEF0202-DOEF0203) Total vegetation maintenance spans (DOEF0204)	Urban and Rural vegetation maintenance spans data has been sourced from June monthly reports for the Annual Vegetation Management Program which are based on the Ellipse database (i.e. 2012/13 data was found in the June 2013 report). Total completed (actual) spans figures for Urban Vegetation Zones and Total completed (actual) spans and for Rural Vegetation Zones where reported (Ergon Energy has no CBD feeder categories). 2008/09 span figures for Rural, Urban and Totals have been sourced from Works Delivery Manager archive reports. As these figures are not from a database, figures have been recorded as an Estimate. Total vegetation maintenance spans (DOEF0204) is simply the sum of DOEF0202 and DOEF0203 for each regulatory year. Information provided is Actual Information for the full five regulatory years provided. As per AER clarifications provided on 3 December 2013, Ergon Energy confirms that for vegetation maintenance span variables DOEF0202 to DOEF0205, data does not include spans in the network service area where a DNSP is not responsible for the vegetation management associated with the span.
Total number of spans (DOEF0205)	Total number of spans for 2012/13 in respect of Ergon Energy's network has been sourced from Smallworld. Information provided for 2012/13 is considered Actual Information (as per the AER defined term). On 3 December 2013, the AER clarified that DOEF0205 requests the number of spans within a DNSP's network irrespective of whether they are vegetation management spans. Accordingly, Ergon Energy confirms DOEF0205 does not include service line spans. It is the total number of spans, excluding service line spans. Data is not readily available to allow Ergon Energy to determine the number of spans for non-current regulatory years prior to 2012/13. Accordingly, Estimated Information has been provided for 2005/06-2011/12. The estimate is based on the assumption that the number of spans will vary proportionately with the overall network length. The number of spans was estimated based on the change in conductor length

<table>
<tr><th>Variable</th><th>Addressing Basis of Preparation Requirements</th></tr>
<tr><td></td><td>between the regulatory year 2008/09 and the 2012/13 year.

The change in conductor length is based on circuit length values calculated in template 6 table 6.1.1 (overhead network length of circuit at each voltage level).</td></tr>
<tr><td>Average urban and CBD vegetation maintenance span cycle (DOEF0206)

Average rural vegetation maintenance span cycle (DOEF0207)</td><td>2012/13 average maintenance span cycle data was calculated based on data sourced from the June monthly report for the Annual Vegetation Management Program (June 2013) taken from the Ellipse database (i.e. 2012/13 data was found in the June 2013 report).

A methodology was employed whereby:
Average urban vegetation maintenance span cycle = (Sum of treated Urban vegetation zones cycle duration [Maintenance Schedule Task] / total number of Urban Vegetation Zones treated during regulatory (financial) year);
Average rural vegetation maintenance span cycle = (Sum of treated rural vegetation zones cycle duration [Maintenance Schedule Task] / total number of rural Vegetation Zones treated during regulatory (financial) year)
(Ergon Energy has no CBD feeder categories).

For regulatory 2008/09 through 2011/12, data was calculated from historical treatment dates found within the Tree Management Database. Cycle length was interpreted as the time between treatment information entries for each Vegetation Zone.

A methodology was employed for these regulatory years, such that:
Average urban vegetation maintenance span cycle = (Sum of time between treatments for all Urban vegetation zones treated within a financial year / number of Urban vegetation zones treated in that year);
Average rural vegetation maintenance span cycle = (Sum of time between treatments for all Rural vegetation zones treated within a financial year / number of Rural vegetation zones treated in that year)
Note: Some error is included in these calculations, as treatment information entries may be for small one-off “touch up” work undertaken in between full treatments.

Furthermore, methodologies / calculations are not based on the numbers of spans in each vegetation zone and as such results may not be representative of the true “average span”.

Accuracy of information likely declines prior to 2009/10.

Information provided for 2012/13 is considered Actual in accordance with AER requirements.</td></tr>
<tr><td>Average number of trees per urban and CBD vegetation maintenance span (DOEF0208)

Average number of</td><td>On 7 February 2014 the AER provided additional guidance to NSPs regarding the definition of a ‘Tree’ for the purposes of measuring the average number of trees per vegetation maintenance span for variables DOEF0208 and DOEF0209. The AER noted it considered a tree to be:

a perennial plant (of any species including shrubs) that is:
equal to or greater in height than 3 metres (measured from the ground) in</td></tr>
</table>

Variable	Addressing Basis of Preparation Requirements
trees per rural vegetation maintenance span (DOEF0209)	*the relevant reporting period; and* • *of a species which could grow to a height such that it may impinge on the vegetation clearance space of power lines.* In providing this clarification the AER noted this definition was not provided as part of the economic benchmarking RIN and that DNSPs may have applied a different, compliant definition in collecting data. Information provided for 2012/13 is considered Actual in accordance with AER requirements. For 2012/13 information Ergon Energy has sourced data from its Remote Observation Automated Modelling Economic Simulation (ROAMES) LiDAR program. ROAMES seeks to enable Ergon Energy with remote observation capability initially by flying over the network assets in an aerial vehicle equipped with sensor system, processing the resulting data and providing reporting and visualisation back to the business. For Urban vegetation areas, the number of trees was interpreted as number of “intrusions” found within 2.0 metres of the Clearance Zone. From field assessments, this proximity is found to contain almost all trees inspected and treated by vegetation contractors. A methodology was then employed for 2012/13, such that: ▪ Average number of trees per urban and CBD vegetation maintenance span= (Total number of intrusions recorded as occurring within 2.0m from the captured conductor location [as reported at time of analysis] / Total number of ROAMES - reported spans [as reported at time of analysis]) ▪ Note: Some error exists in reported data, as an “intrusion” may not be truly representative of a single tree. For Rural vegetation zones, the number of trees was interpreted as number of “intrusions” found within the treatment corridor as well as those found outside the corridor which could potentially impact on the network upon failure (i.e. potential “hazard” or “danger” trees). ▪ Average number of trees per rural vegetation maintenance span= (Total number of intrusions recorded as occurring within 2.0m from the captured conductor location [as reported at time of analysis] / Total number of ROAMES - reported spans [as reported at time of analysis]) ▪ Note: Some error exists in 2012/13 data provided, as an “intrusion” may not be truly representative of a single tree. Information provided for 2012/13 is considered Actual in accordance with AER requirements. For years prior (i.e. 2008/09-2011/12) information was sourced from historical treatment records contained within the Tree Management Database (TMD). The numbers of trees was calculated from numbers of trims and removals recorded as undertaken in each year. For Urban, the calculation for 2008/09-2011/12 was:

Variable	Addressing Basis of Preparation Requirements
	▪ Average number of trees per urban and CBD vegetation maintenance span= (Total number of trims and removals recorded during the year / number of spans reported as being treated in the year [as reported in DOEF0202]) ▪ Note: Some error exists in provided figures, as TMD-sourced information does not include all trees inspected, nor does it include work undertaken under hourly rate or herbicide application work. For Rural, the calculation for 2008/09-2011/12 was: ▪ Average number of trees per rural vegetation maintenance span = (Total number of trims and removals recorded during the year / number of spans reported as being treated in the year [as reported in DOEF0203]) ▪ Note: Rural estimates are particularly erroneous as most treatment is undertaken using herbicide application, which is recorded as an application rate per hectare and total hectare area treated.
Average number of defects per urban and CBD vegetation maintenance span (DOEF0210) Average number of defects per rural vegetation maintenance span (DOEF0211)	Ergon Energy has not provided data in the orange shaded cells for variables DOEF0210 and DOEF0211 in regulatory years 2008/09 to 2011/12 (inclusive), as data is not currently measured in accordance with the AER's requirements, and it would be unnecessarily burdensome to estimate. Furthermore, it would be illogical to enter "0". Data in relation to 2012/13 was sourced from Ergon Energy's ROAMES LiDAR program. A "defect" was classified as per the Ergon Energy Defect Classification Manual. Vegetation related defects are those found within an unsafe proximity to a bare high voltage conductor, classed as a "CP intrusion" under the Ergon Energy Specification for ROAMES Modelling and Reporting of Vegetation Clearance Bands. A calculation has then be done as follows: ▪ Average number of defects per urban and CBD vegetation maintenance span = (number of "CP intrusions" reported in Urban vegetation zones / number of urban vegetation zone spans reported by ROAMES at time of analysis). ▪ Average number of defects per rural vegetation maintenance span = (number of "CP intrusions" reported in rural vegetation zones / number of rural vegetation zone spans reported by ROAMES at time of analysis). Information provided for 2012/13 is considered Actual in accordance with AER requirements.
Tropical proportion (DOEF0212)	Ergon Energy has not provided data in the orange shaded cells for variable DOEF0212 in regulatory years 2008/09 to 2011/12 (inclusive), as data is not currently measured in accordance with the AER's requirements, and it would be unnecessarily burdensome to estimate. Furthermore, it would be illogical to enter "0". For 2012/13, the tropical proportion of Ergon Energy's network was based on network data sourced from the Smallworld GIS. The number of spans occurring

Variable	Addressing Basis of Preparation Requirements
	within hot humid summer and warm humid summer regions (as defined by the BOM Climatic Zones map) was assessed using .shp files sourced from the BOM website. Information provided for 2012/13 is considered Actual in accordance with the AER's requirements. Estimates have been provided for DOEF0212 for years prior to 2012/13. Figures assume that network configuration, tropical proportion (DOEF0212) has not changed prior to 2012/13. Figures used are copied from Actual Information submitted for 2012/13 year.
Standard vehicle access (DOEF0213)	For 2012/13, an assessment of data sourced from Smallworld was required. A query was undertaken to return line length within 50m of the centreline of selected road reserves which were deemed to be suitable for two wheel drive vehicles. The reserves selected were: Highway; Local Connector Road; Main Road; Roundabout, intersection; Seeled Road; Unsealed Road. Information provided for 2012/13 is considered Actual in accordance with the AER's requirements. Estimates have been provided for DOEF0213 for years prior to 2012/13. Figures assume that network configuration, Standard vehicle access (DOEF0213) has not changed prior to 2012/13. Figures used are copied from Actual Information submitted for 2012/13 year.
Bushfire risk (DOEF0214)	For 2012/13 the number of spans found occurring within High Bushfire Risk Areas, as defined by spatial data previously obtained from the Queensland Rural Fire Service was ascertained through an assessment an assessment of data sourced from the Smallworld GIS. Information provided for 2012/13 is considered Actual in accordance with the AER's requirements. Estimates have been provided for DOEF0214 for years prior to 2013. Figures assume that network configuration, Bushfire risk (DOEF0214) has not changed prior to 2013. Figures used are copied from Actual Information submitted for 2013 year.

4.2.9.3 Service Area Factors

The AER requires information in template 8, table 8.3 in relation to Ergon Energy's' route Line Length of lines in its network. This is required to be based on the distance between line segments and to not include vertical components such as line sag. The route Line Length does not necessarily equate to the circuit length as the circuit length may include multiple circuits.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to route line length.

Table 4-51: Route Line Length

Variable		Addressing Basis of Preparation Requirements
DOEF0301	A	All mandatory data entry fields shaded yellow, and have been populated for each of the regulatory years. Route Line length of lines is based on the distance between line segments. It does not include vertical components such as line sag. The route Line Length does not equate to the circuit length as the circuit length includes multiple circuits. The circuit length is reported excluding the circuit length of service lines. Following AER clarifications provided in relation to variable DOEF0301 which noted the intent of this variable is to measure the aggregate distance between poles and/or towers, Ergon Energy confirms that where: ▪ two sets of lines that run on different sets of poles (or towers) share the same easement the lines are counted separately; ▪ there are multiple circuits on a span, the length of each span is considered only once; and ▪ a span shares multiple voltages, the length of the span is also considered only once; and ▪ captures the length of both underground cables and overhead lines
	B	Ergon Energy has sourced data from its SOREP Oracle Spatial database. This database is replicated from the Smallworld GIS electrical data store.
	C	For 2012/13 a methodology was employed whereby data was obtained for the current regulatory year (2012/13) by overlaying all conductors and cables in the system and then dissolving all the conductors and cables which overlapped, into one line segment. The route length of the conductors was then calculated using Feature Manipulation Engine (FME). Refer response to 'D' with regards to methodology employed (including assumptions applied) to develop Estimated Information for the period 2008/09 to 2011/12.
	D	Actual information was provided in relation to Route Line Length for the current (2012/13) regulatory year only. Data is not readily available to allow Ergon Energy to determine route length for non-current regulatory years. Accordingly, Estimated Information has been provided for the period 2005/06 to 2011/12. The estimate is based on the assumption that the route length will vary proportionately with the overall network length. That is to say, the route length for years prior to the current regulatory year was estimated based on the change in conductor length between the regulatory year and the 2012/13 year. The change in conductor length is based on circuit length values calculated in template 6 table 6.1.1 (overhead network length of circuit at each voltage level) and table 6.1.2 (underground network length of circuit at each voltage level).

Variable		Addressing Basis of Preparation Requirements
	E	Route Line Length reported is a non-financial data set, and accordingly this requirement is not applicable.

4.2.9.4 Weather Stations

The AER requires Ergon Energy to provide details relating to the Weather Station in its service area. Specifically template 8, table 8.4 requires weather station numbers, post codes, suburb/localities, based on details available from the Australian Governments, Bureau of Meteorology (BOM).

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables in relation to Weather Stations.

Table 4-52: Weather Stations

Variable		Addressing Basis of Preparation Requirements
DOEF04001-DOEF04221	A	All mandatory data entry fields shaded yellow, have been populated for each of the weather stations in Ergon Energy's service area. Ergon Energy has input a variable code for each weather station in its service area recorded in the BOM database as of (2012) with 30 minutes minimum readings, inserting rows as relevant. Where deemed to not be relevant to the management of its network, Ergon Energy has input a 'no' in the 'materiality' column of the table and provided supporting evidence as to why the weather station is not relevant. For all other stations, a 'yes' was entered in the materiality column.
	B	Data has been sourced from the BOM website (www.bom.gov.au) and imported into Ergon Energy's Network Analytics Oracle Spatial database with LANDBASE Oracle Spatial database.
	C	Each Automatic Weather Station (AWS) was analysed based on frequency of readings and only AWS with 30 minutes minimum readings were used. AWS readings are not currently used for Network Operations but there are projects underway to utilise this information. AWS locations were determined by spatial analysis relating to Queensland suburb locality boundaries. Data from AWS locations with Materiality of 'No' are not relevant for Ergon Energy network planning purposes as the data quality and frequency are considered not viable.
	D	Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in template 8 table 8.4.
	E	Weather station data is non-financial, and accordingly this requirement is not applicable.

5. AUDIT AND REVIEW REPORTS

RIN - Schedule 1 paragraph 1.4, Schedule 2 paragraph 2.5, Appendix D, Instruction and Definitions

5.1 Requirement

The Notice requires Ergon Energy's completed Templates and basis of preparation to be independently audited and verified by suitably qualified auditors.

Schedule 1 paragraph 1.4 requires the provision of Audit Report(s) and Review Report(s) as applicable, to be prepared in accordance with the requirements of the Notice, Instructions and Definitions at Appendix B and the Audit requirements in Appendix D of the Notice.

Furthermore, Paragraph 2.5 of Schedule 2 requires Ergon Energy to prepare these reports, using a person(s) who satisfies the requirements of paragraph 2 of Appendix D, in accordance with the requirements of the Notice and the Instructions and Definitions.

The Class of Person to conduct Audits is noted in Appendix D, paragraph 2.

Information subject to Audit includes all financial and non-financial information, whether estimated or actual. Audit and Review requirements (including the applicable Standards and opinion or conclusions required) are set out in Appendix D, paragraph 3.

Of note, the Covering Letter and the *Matters the Subject of this Notice* in the RIN specifically denoted that relevant to the initial regulatory years, Audit Report/Review Reports to the AER are required to accompany the Final Submission of the Benchmarking RIN response, as due to the AER by 30 April 2014 (presented and discussed herein).

5.2 Response

Ergon Energy notes the following auditors were appointed to audit its 2005/06-2012/13 Economic Benchmarking RIN and associated templates (as relevant):

- Parsons Brinckerhoff (PB) to audit Non-Financial (actual or estimated) in accordance with the Audit scope at Appendix D paragraphs 2.2 and paragraph 3.4 of the RIN.
- Auditor-General of Queensland to audit Financial Information (actual or estimated) in accordance with the Audit scope at Appendix D paragraphs 2.1 and 3.1-3.3 of the RIN;

It is noted that in regard to the appointment of the Auditor-General of Queensland discussions were held with other Auditor-Generals' representatives around the country and a representative from the AER. Concern was raised, given requirements in Appendix D paragraph 2.1(a) of the Notice for the person to conduct the Financial Information audits to be a person who holds a Certificate of Public Practice.

This requirement precludes all Auditor-Generals from undertaking an audit of Ergon Energy's Benchmarking RIN given they do not hold a Certificate of Public Practice.

The AER has advised that this drafting was unintentional and issued correspondence to the Auditor-Generals advising them should an Auditor-General be appointed, it would be appropriate to contract auditors who hold certificates of public practice as part of the engagements to satisfy Notice requirements.

In this regard, the Auditor-General of Queensland appointed Deloitte who hold certificates of public practice as part of the engagements to satisfy Notice requirements.

As required under Schedule 1 paragraph 1.4 of the Notice, Ergon Energy provides the following results of the abovementioned audits as attachments to this submission, namely the Audit Report(s) and Review Report(s):

- Parsons Brinckerhoff - Review Report (Non-Financial Information – Estimated and Actual) [**EE_0506-1213EBRIN_004F**]**;**
- Queensland Audit Office - Audit Opinion (Financial Information - Actual) [**EE_0506-1213EBRIN_005F**]; **and**
- Queensland Audit Office - Audit Report (Financial Information - Estimated) [**EE_0506-1213EBRIN_006F**].

6. STATUTORY DECLARATION

RIN - Schedule 2, Appendix C

6.1 Requirement

The AER requires Ergon Energy to verify information provided under the Notice, by way of a statutory declaration by an Officer of the Company in accordance with Appendix C to the Notice. A pro forma Statutory Declaration was provided in this regard.

Similar to the purview of the Audit scope, information subject to Statutory Declaration includes all financial and non-financial information, whether estimated or actual.

A signed Statutory Declaration relevant to the initial regulatory years is required to accompany a Final Submission to the AER's Notice, as due to the AER by 30 April 2014 (presented and discussed herein).

6.2 Response

Ergon Energy herein provides a Statutory Declaration signed by an Officer of Ergon Energy Corporation Limited, as attachment **EE_0506-1213EBRIN_007F.**

7. APPENDIX A – LIST OF ATTACHMENTS

Table 7-1: List of Attachments (Final Submission)

Title	Attachment
EE_0506-1213EBRIN_001F	Ergon Energy's 2005/06-2012/13 Economic Benchmarking RIN Templates, Consolidated Information
EE_0506-1213EBRIN_002F	Ergon Energy's 2005/06-202/13 Economic Benchmarking RIN Templates, Estimated Information
EE_0506-1213EBRIN_003F	Ergon Energy's 2005/06-2012/13 Economic Benchmarking RIN Templates, Actual Information
EE_0506-1213EBRIN_004F	Parsons Brinckerhoff - Review Report (Non-Financial Information – Estimated and Actual)
EE_0506-1213EBRIN_005F	Queensland Audit Office - Audit Opinion (Actual Financial Information)
EE_0506-1213EBRIN_006F	Queensland Audit Office - Audit Review Report (Estimated Financial Information)
EE_0506-1213EBRIN_007F	Ergon Energy Corporation Limited, Statutory Declaration

Customer Service
13 10 46
7.00am – 6.30pm, Monday to Friday

Faults Only
13 22 96
24 hours a day, 7 days a week

Life-Threatening Emergencies Only
Triple zero (000) or 13 16 70
24 hours a day, 7 days a week

Ergon Energy Corporation Limited ABN 50 087 646 062
Ergon Energy Queensland Pty Ltd ABN 11 121 177 802

ergon.com.au